Montana Department of
ENVIRONMENTAL QUALITY

Brian Schweitzer, Governor

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February 9, 2012

Dana Leach
Montana Refining Company
1900 10th Street North East
Great Falls, MT 59404

Dear Mr. Leach:

Montana Air Quality Permit #2161-25 is deemed final as of February 9, 2012, by the Department of Environmental Quality (Department). This permit is for a petroleum refinery. All conditions of the Department's Decision remain the same. Enclosed is a copy of your permit with the final date indicated.

For the Department,

Vickie Walsh Jenny O'Mara

Vickie Walsh
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VW:JO

Montana Department of Environmental Quality
Permitting and Compliance Division

Montana Air Quality Permit #2161-25

Montana Refining Company
1900 10th Street North East
Great Falls, MT 59404

February 9, 2012

MONTANA AIR QUALITY PERMIT

Issued to: Montana Refining Company
1900 10th Street North East
Great Falls, MT 59404

MAQP: #2161-25
Application Complete: 11/15/2011
Preliminary Determination: 12/21/2011
Department Decision: 01/24/2012
Permit Final: 02/09/2012
AFS#: 013-0004

A Montana Air Quality Permit (MAQP), with conditions, is hereby granted to the Montana Refining Company (MRC) pursuant to Sections 75-2-204, 211, and 215 of the Montana Code Annotated (MCA), as amended, and the Administrative Rules of Montana (ARM) 17.8.740, *et seq*., as amended, for the following:

SECTION I: Permitted Facilities

A. Plant Location

MRC operates a petroleum refinery located at the NE ¼ of Section 1, Township 20 North, Range 3 East, in Cascade County, Montana. The refinery is located along the Missouri River in Great Falls, Montana.

B. Permitted Facility

The major permitted equipment at MRC includes:

- Crude Unit;
- Fluid Catalytic Cracking Unit (FCCU);
- Hydrogen Plant #1 and #2;
- Catalytic Reformer Unit;
- Naptha Hydrodesulfurization (HDS);
- Diesel HDS;
- Catalytic Poly Unit;
- Hydrogen Fluoride (HF) Alkylation Unit;
- Deisobutanizer Unit;
- Sodium Hydrosulfate (NaHS) Unit;
- Diesel/Gas Hydrotreater Unit (HTU);
- Polymer-Modified Asphalt (PMA) Unit;
- Storage Tanks (heated asphalt, crude oil, and petroleum products);
- Gasoline Truck Loading with a vapor combustor unit (VCU);
- Gasoline Railcar Loading with a VCU; and
- Utilities (Boilers (#1, #2 and #3), cooling towers, wastewater treatment).

A complete list of permitted equipment for MRC is contained in Section I.A. of the permit analysis.

C. Current Permit Action

On July 6, 2011, MRC submitted a permit application and subsequent modeling demonstration to add a new boiler (Boiler #3) capable of firing refinery fuel gas or natural gas. The primary purpose of Boiler #3 is to supplement the two existing boilers

(#1 and #2) that provide process steam to the refinery. The design burner heat input capacity for Boiler #3 varies depending upon fuel characteristics ranging from 59.7 to 60.3 million british thermal units per hour (MMBtu/hr). The Department deemed the application incomplete on August 4, 2011, and MRC provided additional information in response to the Department's letter on September 26, 2011.

On October 25, 2011, the Department requested additional information with respect to MRC's plantwide applicability limit (PAL) and the fuel combustion properties of the caustic scrubbed sour water stripper overhead gas (SWSOH). This information, and a request to allow a backup method of monitoring compliance with sulfur dioxide (SO_2) emissions from the #1 and #2 Boiler stack and the #3 Boiler stack were received by the Department on November 15, 2011.

SECTION II: Limitations and Conditions

A. General Facility Conditions

1. MRC shall comply with all applicable requirements of ARM 17.8.340, which references 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS):

   a. Subpart A – General Provisions shall apply to all equipment or facilities subject to an NSPS Subpart as listed below.

   b. Subpart Dc - Standards of Performance for Small Industrial-Commercial Institutional Steam Generating Units for which construction, modification, or reconstruction is commenced after June 9, 1989. This Subpart applies to the #3 Boiler.

   c. Subpart J - Standards of Performance for Petroleum Refineries shall apply to the following affected facilities, as described:

      i. FCCU regenerator: for carbon monoxide (CO) and SO_2 (MRC Consent Decree).

      ii. Heaters and boilers (MRC Consent Decree).

   d. Subpart Ja – Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification commenced after May 14, 2007. The #3 Boiler meets the applicability requirement of this Subpart; however, requirements for fuel gas combustion devices have been stayed until further notice.

   e. Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels shall apply to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after July 23, 1984.

   f. Subpart UU – Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture shall apply to all asphalt storage tanks that processes and stores only non-roofing asphalts, and was constructed or modified since May 26, 1981.

g. Subpart VV – Standards of Performance for Equipment Leaks of Volatile Organic Compounds (VOC) in the Synthetic Organic Chemicals Manufacturing Industry, shall apply to this refinery as required by 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC.

h. Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries shall apply to the NaHS Unit, Diesel/Gas Oil HDS Unit, Hydrogen Plant, and any other equipment as appropriate. A monitoring and maintenance program as described under 40 CFR 60, Subpart VV shall be instituted.

i. Subpart QQQ – Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems shall apply to the HTU, Hydrogen Unit, and any other equipment as appropriate.

2. MRC shall comply with all applicable requirements of ARM 17.8.342, as specified by 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants (NESHAP) for Source Categories:

a. Subpart A – General Provisions applies to all equipment or facilities subject to a NESHAP for source category subpart as listed below.

b. Subpart R – NESHAP for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations), as specified under Subpart CC.

c. Subpart CC – NESHAP from Petroleum Refineries shall apply to, but not be limited to, the bulk loading racks (including the gasoline truck loading and railcar loading racks), certain valves and pumps in the alkylation unit, miscellaneous process vents, storage vessels, wastewater, and equipment leaks. The gasoline loading rack provisions in Subpart CC require compliance with applicable Subpart R provisions, and the equipment leak provision requires compliance with applicable 40 CFR 60, Subpart VV provisions.

d. Subpart UUU – NESHAP from Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, shall apply to, but not be limited to, the FCCU and the Catalytic Reformer Unit.

e. Subpart EEEE – NESHAP for Organic Liquids Distribution (Non-Gasoline) shall apply to, but not be limited to, Tank # 1 – Diethylene glycol monoether (DEGME) and the naphtha loading rack.

B. Emission Control Requirements:

MRC shall install, operate and maintain the following equipment and practices as specified:

1. The refinery flare shall be utilized for emergency use only (ARM 17.8.749 and ARM 17.8.752).

2. Hydrogen plant reformer heaters shall only be fired with commercially available natural gas, which may include recycled gas from the hydrogen plants, and shall not be fired with refinery fuel gas or refinery Liquefied Petroleum Gas (LPG). The diesel/gas oil HDS heater shall be fired with only purchased natural gas or refinery fuel gas that meets 40 CFR 60, Subpart J requirements. The purge (vent) gas used as fuel in the hydrogen plant reformer heaters shall be sulfur-free (ARM 17.8.752).

3. Hydrogen Plant #2 must be equipped with a next-generation ultra-low NO_x burner (ULNB) on the heater (MRC Consent Decree and ARM 17.8.749).

4. Storage Tanks:

   a. Storage tanks #52, #53, and #57 shall be equipped with double seal internal floating roofs (ARM 17.8.752).

   b. Storage tanks #122, #123, #124, #125, and #126 shall be equipped with dual-seal external floating roofs (ARM 17.8.752).

   c. Storage tanks #127 and #128 shall be equipped with dual-seal external floating roofs. The primary seals shall be visually inspected for holes every 5 years and the secondary seals shall be visually inspected for holes annually (ARM 17.8.752).

   d. Storage tanks #9, #50, #55, #56, #69 #102, #110, #112, #130, #132, #133, and #135 shall be used for heavy oil (ARM 17.8.749).

   e. Storage tank #8 shall be used for light oil (ARM 17.8.749).

   f. Storage tanks #137, #139, and #140 shall be used for heavy oil (ARM 17.8.749).

   g. Asphalt tank heaters #102, #135, #137, #139 and #140 shall burn only natural gas or refinery fuel gas in compliance with 40 CFR 60, Subpart J (ARM 17.8.749, Consent Decree, and 40 CFR 60, Subpart J).

   h. The three 0.75 MMBtu/hr PMA tank heaters (tanks #130, #132, and #133), shall burn natural gas or refinery fuel gas in compliance with 40 CFR 60, Subpart J (ARM 17.8.752, Consent Decree, and 40 CFR 60, Subpart J).

   i. MRC shall not cause to be discharged into the atmosphere from any asphalt tank constructed or modified since May 26, 1981, exhaust gases with opacity greater than 0% except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being blown for clearing (ARM 17.8.340 and 40 CFR 60, Subpart UU).

   j. For any asphalt tank constructed between November 23, 1968, and May 26, 1981, or any other tank constructed since November 23, 1968, MRC shall not cause to be discharged into the atmosphere exhaust gases with an opacity of 20% or greater, averaged over 6 consecutive minutes (ARM 17.8.304).

   k. For any tank constructed prior to November 23, 1968, MRC shall not cause to be discharged into the atmosphere exhaust gases with an opacity of 40% or greater, averaged over 6 consecutive minutes (ARM 17.8.304).

5. Pressure Vessels – All pressure vessels in HF Acid service, except storage tanks, shall be vented to the flare system (ARM 17.8.749 and ARM 17.8.752).

6. The HF Alkylation Unit shall be operated and maintained as follows (ARM 17.8.749 and ARM 17.8.752):

   a. All valves used shall be high quality valves containing high quality packing.

   b. All open-ended valves shall be of the same quality as the valves described above. They shall have plugs or caps installed on the open end.

   c. All pumps used in the alkylation plant shall be fitted with the highest quality state-of-the-art mechanical seals.

   d. All pumps shall be monitored and maintained as described in 40 CFR Part 60.482-2 and all control valves shall be monitored and maintained as described in 40 CFR Part 60.482-7. All other potential sources of VOC leaks shall be inspected quarterly for evidence of leakage by visual or other detection methods. Repairs shall be made promptly as described in 40 CFR Part 482-7(d). Records of monitoring and maintenance shall be maintained on site for a minimum of 2 years.

   e. All process drains shall consist of water seal traps with covers.

   f. All equipment shall be operated and maintained as described in 40 CFR Parts 60.692-2, 60.692-6, and 60.693-1. Inspection reports shall be made available for inspection upon request.

   g. The Alkylation Unit process heater shall burn only natural gas or fuel gas in compliance with 40 CFR 60, Subpart J (ARM 17.8.749, Consent Decree, and 40 CFR 60, Subpart J).

7. The PMA Unit shall be operated and maintained as follows:

   a. All open-ended valves shall have plugs or caps installed on the open end (ARM 17.8.752).

   b. All pumps in the PMA unit shall be equipped with standard single seals (ARM 17.8.752).

   c. All pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors shall meet the standards described in 40 CFR Part 60.482-8. Repairs shall be made promptly as described in 40 CFR Part 60.482-7(e) (ARM 17.8.752).

8. MRC shall ensure that the NaHS Unit, Diesel/Gas Oil HDS Unit, Hydrogen Plants, and any other equipment as appropriate, comply with the applicable requirements in 40 CFR 63, Subpart GGG, including (ARM 17.8.342 and 40 CFR 63, Subpart GGG):

   a. All valves used shall be high quality valves containing high quality packing.

   b. All open-ended valves shall be of the same quality as the valves described above. They shall have plugs or caps installed on the open end.

   c. A monitoring and maintenance program as described under 40 CFR 60, Subpart VV shall be instituted.

9. MRC shall ensure that all process drains consist of water seal traps with covers, for the HTU, Hydrogen Units, and any other equipment as appropriate (ARM 17.8.342 and 40 CFR 63, Subpart QQQ).

10. Cooling Towers – Cooling water shall be monitored twice per shift for changes, specifically pH and hydrocarbon content. The appearance of the towers and related equipment shall be inspected at least once per shift (ARM 17.8.749 and ARM 17.8.752).

11. MRC must install, operate, and maintain ULNB and flue gas recirculation (FGR) on the #3 Boiler (ARM 17.8.752).

12. The #3 Boiler shall only combust pipeline quality natural gas, refinery fuel gas or SWSOH (ARM 17.8.752).

13. When the SO_2/O_2 Continuous Emissions Monitoring System (CEMs) is operational on the boiler stacks, MRC may incinerate the HTU SWSOH in the #1, #2 and #3 boilers. Incineration of the SWSOH and combustion of any refinery fuel gas shall meet the applicable limitations in 40 CFR 60, Subpart J (Consent Decree, ARM 17.8.340, ARM17.8.749, and 40 CFR 60, Subpart J).

14. MRC shall not re-activate the old SWS unit that was taken out of stripping service in 2006, without conducting a permitting analysis in conformance with ARM 17.8 Subchapter 7, and obtaining Department approval, in writing (ARM 17.8.749).

15. The gasoline and distillates truck loading rack shall be operated and maintained as follows:

    a. MRC's tank truck loading rack shall be equipped with a vapor collection system designed to collect the organic compound vapors displaced from cargo tanks during gasoline product loading (ARM 17.8.342).

    b. MRC’s collected vapors shall be routed to the VCU at all times. In the event the VCU is inoperable, MRC may continue to load distillates with a Reid vapor pressure of less than 27.6 kilopascals, provided the Department is notified in accordance with the requirements of ARM 17.8.110 (ARM 17.8.752).

    c. The vapor collection and liquid loading equipment shall be designed and operated to prevent gauge pressure in the gasoline cargo tank from exceeding 4,500 Pascals (Pa) (450 millimeters [mm] of water) during product loading. This level shall not be exceeded when measured by the procedures specified in the test methods and procedures in 40 CFR Part 60.503(d) (ARM 17.8.342 and 40 CFR 63, Subpart CC).

    d. No pressure-vacuum vent in the permitted terminal's vapor collection system shall begin to open at a system pressure less than 4,500 Pa (450 mm of water) (ARM 17.8.342).

    e. The vapor collection system shall be designed to prevent any VOC vapors collected at one loading position from passing to another loading position (ARM 17.8.342).

f. Loadings of liquid products into gasoline cargo tanks shall be limited to vapor-tight gasoline cargo tanks, using the following procedures (ARM 17.8.342):

i. MRC shall obtain annual vapor tightness documentation described in the test methods and procedures in 40 CFR Part 63.425(e) for each gasoline cargo tank that is to be loaded at the truck loading rack;

ii. MRC shall require the cargo tank identification number to be recorded as each gasoline cargo tank is loaded at the terminal;

iii. MRC shall cross-check each tank identification number obtained during product loading with the file of tank vapor tightness documentation within 2 weeks after the corresponding cargo tank is loaded;

iv. MRC shall notify the owner or operator of each non-vapor-tight cargo tank loaded at the truck loading rack within 3 weeks after the loading has occurred; and

v. MRC shall take the necessary steps to ensure that any non-vapor-tight cargo tank will not be reloaded at the truck loading rack until vapor tightness documentation for that cargo tank is obtained which documents that:

aa. The gasoline cargo tank meets the applicable test requirements in 40 CFR Part 63.425(e) to this permit;

bb. For each gasoline cargo tank failing the test requirements in 40 CFR Part 63.425(f) or (g), the gasoline cargo tank must either:

1. Before the repair work is performed on the cargo tank, meet the test requirements in 40 CFR Part 63.425(g) or (h), or

2. After repair work is performed on the cargo tank, before or during the tests in 40 CFR Parts 63.425(g) or (h), subsequently passes, the annual certification test described in 40 CFR Part 63.425(e).

g. MRC shall ensure that loadings of gasoline cargo tanks at the truck loading rack are made only into cargo tanks equipped with vapor collection equipment that is compatible with the terminal's vapor collection system (ARM 17.8.342).

h. MRC shall ensure that the terminal and the cargo tank vapor recovery systems are connected during each loading of a gasoline cargo tank at the truck loading rack (ARM 17.8.342).

i. MRC shall monitor and maintain all pumps, shutoff valves, relief valves, and other piping and valves associated with the gasoline loading rack as described in 40 CFR Parts 60.482-1 through 60.482-10.

j. The truck loading rack VCU stack shall be at least 35 feet above grade (ARM 17.8.749).

16. The gasoline railcar loading rack and VCU shall be operated and maintained as follows:

    a. Gasoline and naphtha will be the only products loaded from the gasoline railcar loading rack (ARM 17.8.749).

    b. MRC's gasoline railcar loading rack shall be equipped with a vapor recovery system designed to collect the organic compounds displaced from railcar product loading and vent those emissions to the VCU (ARM 17.8.342 and 40 CFR 63, Subpart CC and ARM 17.8.752).

    c. MRC shall operate and maintain the VCU to control VOC and hazardous air pollutant (HAP) emissions during the loading of gasoline or naphtha in the gasoline railcar loading rack. MRC's collected vapors shall be routed to the VCU at all times (ARM 17.8.752).

    d. The vapor recovery system shall be designed to prevent any VOC vapors collected at one loading position from passing to another loading position (ARM 17.8.749).

    e. Loading of gasoline and naphtha railcars shall be restricted to the use of submerged fill and dedicated normal service (ARM 17.8.752).

    f. MRC shall ensure that loading of railcars at the gasoline railcar loading rack are made only into railcars equipped with vapor recovery equipment that is compatible with the terminal's vapor recovery system (ARM 17.8.749).

    g. Loadings of gasoline into gasoline cargo tanks shall be limited to vapor-tight gasoline cargo tanks, using procedures as listed in 40 CFR 63, Subpart R (ARM 17.8.342 and 40 CFR 63, Subpart CC, and ARM 17.8.752).

        i. MRC shall obtain annual vapor tightness documentation described in the test methods and procedures in 40 CFR Part 63.425(e) for each gasoline cargo tank that is to be loaded at the railcar loading rack;

        ii. MRC shall require the cargo tank identification number to be recorded as each gasoline cargo tank is loaded at the terminal;

        iii. MRC shall cross-check each tank identification number obtained during product loading with the file of tank vapor tightness documentation within 2 weeks after the corresponding cargo tank is loaded;

        iv. MRC shall notify the owner or operator of each non-vapor-tight cargo tank loaded at the railcar loading rack within 3 weeks after the loading has occurred; and

        v. MRC shall take the necessary steps to ensure that any non-vapor-tight cargo tank will not be reloaded at the railcar loading rack until vapor tightness documentation for that cargo tank is obtained which documents that:

            aa. The gasoline cargo tank meets the applicable test requirements in 40 CFR Part 63.425(e) to this permit;

bb. For each gasoline cargo tank failing the test requirements in 40 CFR Part 63.425(f) or (g), the gasoline cargo tank must either:

1. Before the repair work is performed on the cargo tank, meet the test requirements in 40 CFR Part 63.425(g) or (h), or

2. After repair work is performed on the cargo tank, before or during the tests in 40 CFR Part 63.425(g) or (h), subsequently passes, the annual certification test described in 40 CFR 63.425(e).

h. MRC shall ensure that the terminal's and the railcar's vapor recovery systems are connected during each loading of a railcar at the gasoline railcar loading rack (ARM 17.8.749).

i. The vapor recovery and liquid loading equipment shall be designed and operated to prevent gauge pressure in the gasoline railcar from exceeding 4,500 Pa (450 mm of water) during gasoline loading. This level shall not be exceeded when measured by the procedures specified in 40 CFR Part 60.503(d) (ARM 17.8.342 and 40 CFR 63, Subpart CC).

j. No pressure-vacuum vent in the permitted terminal's vapor recovery system shall begin to open at a system pressure less than 4,500 Pa (450 mm of water) (ARM 17.8.749).

k. MRC shall comply with the applicable provisions of 40 CFR 60, Subpart VV, including MRC shall monitor and maintain all pumps, shutoff valves, relief valves, and other piping and valves associated with the gasoline loading rack as described in 40 CFR Parts 60.482-1 through 60.482-10 (ARM 17.8.749, ARM 17.8.342 and 40 CFR 63, Subpart CC).

l. The gasoline railcar loading rack VCU stack exhaust exit shall be at least 30 feet above grade (ARM 17.8.749).

17. MRC shall not combust any fuel gas with a hydrogen sulfide (H_2S) concentration in excess of 230 milligram per dry standard cubic meter (mg/dscm) equivalent to 0.10 grains per dry standard cubic foot (gr/dscf) in any fuel gas combustion device (MRC Consent Decree, ARM 17.8.340 and 40 CFR 60, Subpart J).

18. MRC shall not combust fuel oil in any combustion unit, except torch oil may be used in the FCCU Regenerator during FCCU startups (MRC Consent Decree).

19. The crude unit's stack height shall be at least 150 feet above ground level (ARM 17.8.749).

C. Emission Limitations:

1. Plant-wide refinery emissions shall not exceed (ARM 17.8.749):

a. SO_2:

- Annual 1515 tons per year (TPY)
- Daily 4.15 tons/rolling 24-hours

b. CO:

- Annual 4700 TPY
- Daily 12.9 tons/rolling 24-hours

2. #1 & #2 Boiler emissions shall not exceed:

a. SO_2 (ARM 17.8.749):

- Annual 648 TPY averaged over a 1-year period
- Hourly 148 pounds per hour (lb/hr) averaged over 1 year
- 174 lb/hr averaged over a 24-hour period
- 355 lb/hr averaged over a 3-hour period

b. Oxides of Nitrogen (NOx) (ARM 17.8.752):

- Annual 335 TPY
- Hourly 76.50 lb/hr

c. CO (ARM 17.8.752):

- Annual 4.4 TPY
- Hourly 1.00 lb/hr

d. Opacity from the #1 and #2 boilers shall not exceed 40% averaged over any 6 consecutive minutes (ARM 17.8.304).

3. #3 Boiler emissions:

a. Opacity from the #3 Boiler shall not exceed 20% averaged over any 6 consecutive minutes (ARM 17.8.304).

b. NOx emission limit shall be based on the actual performance as demonstrated by the required initial performance test, but shall not exceed 0.019 lb/MMBtu (1.15 lb/hr) on a 3-hour average basis (MRC Consent Decree and ARM 17.8.752).

c. SO_2 emissions shall not exceed 20 parts per million volume, dry (ppmvd) at 0% oxygen (ARM 17.8.752).

d. CO emissions shall not exceed 0.034 lb/MMBtu based on a 3-hour average (ARM 17.8.752).

4. Diesel/Gas Oil HDS Furnace Stack

a. NOx emissions shall not exceed the limit of 0.07 lb/MMBtu, 1.42 lb/hr, or 6.2 TPY (ARM 17.8.752).

b. CO emissions shall not exceed the limit of 0.79 lb/hr or 3.5 TPY (ARM 17.8.752).

c. Opacity shall not exceed 20% averaged over any 6 consecutive minutes (ARM 17.8.304).

5. Hydrogen Plant Reformer Furnace Stack

   a. NO_x emissions shall not exceed the limit of 0.07 lb/MMBtu, 1.90 lb/hr, or 8.3 TPY (ARM 17.8.752).

   b. CO emissions shall not exceed the limit of 0.93 lb/hr or 4.1 TPY (ARM 17.8.752).

   c. Opacity shall not exceed 20% averaged over any 6 consecutive minutes (ARM 17.8.304).

6. Hydrogen Plant #2

   a. NOx emissions from the process heater shall be controlled by a next generation ULNB and shall not exceed 0.033 lb/MMBtu based on the higher heating value (HHV) (ARM 17.8.752 and MRC Consent Decree).

   b. Opacity shall not exceed 20% averaged over any 6 consecutive minutes (ARM 17.8.304).

7. Gasoline Truck Loading Rack

   a. The total VOC emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 10.0 milligrams per liter (mg/L) of gasoline loaded (ARM 17.8.342 and ARM 17.8.752).

   b. The total CO emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 10.0 mg/L of gasoline loaded (ARM 17.8.752).

   c. The total NOx emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 4.0 mg/L of gasoline loaded (ARM 17.8.752).

   d. MRC shall not cause or authorize to be discharged into the atmosphere from the enclosed VCU:

   e. Any visible emissions that exhibit an opacity of 10% or greater (ARM 17.8.752); and

   f. Any particulate emissions in excess of 0.10 gr/dscf corrected to 12% carbon dioxide (CO_2) (ARM 17.8.752).

8. Gasoline Railcar Loading Rack

   a. The total VOC emissions to the atmosphere from the VCU due to loading gasoline into railcars shall not exceed 10.0 mg/L of gasoline loaded (ARM 17.8.342 and 40 CFR Part 63.422, and ARM 17.8.752).

   b. The total CO emissions to the atmosphere from the VCU due to loading gasoline into cargo tanks shall not exceed 10.0 mg/L of gasoline loaded (ARM 17.8.752).

c. The total NO_x emissions to the atmosphere from the VCU due to loading gasoline into cargo tanks shall not exceed 4.0 mg/L of gasoline loaded (ARM 17.8.752).

d. MRC shall not cause or authorize to be discharged into the atmosphere from the enclosed VCU:

i. Any visible emissions that exhibit an opacity of 10% or greater (ARM 17.8.752); and

ii. Any particulate emissions in excess of 0.10 gr/dscf corrected to 12% CO_2 (ARM 17.8.752).

9. FCCU

MRC shall not cause or authorize to be discharged into the atmosphere from the FCCU emissions in excess of:

a. Particulate Matter (PM) 15.0 lb/hr (MRC Consent Decree)

b. Opacity shall not exceed 40%, except for one 6 minute average in any 1 hour (ARM 17.8.304).

c. CO

i. 500 ppmvd, at stack oxygen (or, "uncorrected") (40 CFR 63, Subpart UUU and 40 CFR 60, Subpart J)

ii. 500 ppmvd, corrected to 0% oxygen (O_2) 1-hour average (MRC Consent Decree)

iii. 100 ppmvd, corrected to 0% O_2 on a 365-day rolling average (MRC Consent Decree)

d. SO_2

i. 50 ppmvd, corrected to 0% O_2, on a 7-day rolling average, except for periods of hydrotreater outages (MRC Consent Decree)

ii. 25 ppmvd, corrected to 0% O_2, on a 365-day rolling average (MRC Consent Decree)

e. NOx – the following NOx limits apply until such time as MRC completes the additional catalyst additive demonstration period and Environmental Protection Agency (EPA) establishes the final NOx limits. At that time, the EPA established limits will supersede these interim limits (MRC Consent Decree):

i. 162 ppmvd, corrected to 0% O_2, on a 3-hour rolling average, except for periods of hydrotreater outages

ii. 138 ppmvd, corrected to 0% O_2, on a 365-day rolling average

D. Monitoring Requirements:

1. Refinery Fuel Gas Combustion Devices

MRC shall install, calibrate, maintain, and operate an instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in fuel gases in accordance with the requirements of 40 CFR Parts 60.11, 60.13, and 60 Appendix A, and the applicable performance specification test of 40 CFR Part 60 Appendices B and F, in order to demonstrate compliance with the limit in Section II.B.17 (MRC Consent Decree, ARM 17.8.340 and 40 CFR 60, Subpart J).

2. SWSOH

MRC shall comply with the monitoring requirements contained in 40 CFR 60, Subpart J, during all times when the HTU SWSOH is incinerated in the #1, #2 or #3 Boilers. MRC shall conduct either H_2S monitoring of the SWSOH stream to demonstrate compliance with the limit in Section II.B.17, or SO_2 stack monitoring for the #1, #2 and #3 Boilers to demonstrate compliance with 20 ppm (dry basis, zero percent excess air) SO_2, as approved by the Department, in writing (MRC Consent Decree, ARM 17.8.340 and 40 CFR 60, Subpart J).

3. MRC shall install and use the following continuous emission monitoring system (CEMS) on the FCCU:

   a. SO_2 and O_2 (MRC Consent Decree)

   b. NO_x and O_2 (MRC Consent Decree)

   c. CO and O_2 (MRC Consent Decree, ARM 17.8.342 and 40 CFR 63, Subpart UUU)

   d. Opacity (ARM 17.8.340 and 40 CFR 60, Subpart J, and ARM 17.8.342 and 40 CFR 63, Subpart UUU)

4. MRC shall install, certify, calibrate, maintain and operate the above-mentioned SWSOH and FCCU CEMS in accordance with the requirements of 40 CFR Parts 60.11, 60.13, and Part 60 Appendix A, and the applicable performance specification test of 40 CFR Part 60 Appendices B and F and 40 CFR 60, Subpart J. These CEMS are a means for demonstrating compliance with the relevant emission limits (MRC Consent Decree).

5. By July 1, 2008, MRC shall install and operate an SO_2 and O_2 CEMS on the stack for the #1 and #2 Boilers, to be used as the primary analytical instrument to determine compliance with state and federal SO_2 requirements. By July 1, 2008, MRC shall initially certify the #1 and #2 Boiler SO_2/O_2 CEMS in accordance with 40 CFR Part 60, Performance Specifications 2 and 3. After initial certification, MRC shall conduct annual Relative Accuracy Test Audits (RATA) of the #1 and #2 Boiler SO_2/O_2 CEMS in conformance with 40 CFR Part 60, Appendix F. After initial certification, MRC shall also continue to implement all of the requirements of 40 CFR Part 60.13 and 40 CFR Part 60, Appendices B and F for the #1 and #2 Boilers SO_2/O_2 CEMS (MRC May 2008 Administrative Order on Consent and ARM 17.8.749).

6. MRC shall install and operate an SO_2 and O_2 CEMS on the stack for the #3 Boiler, to be used as the primary analytical instrument to determine compliance with state and federal SO_2 requirements. MRC shall initially certify the #3 Boiler SO_2/O_2 CEMS in accordance with 40 CFR Part 60, Performance Specifications 2 and 3. After initial certification, MRC shall conduct annual RATA of the #3 Boiler SO_2/O_2 CEMS in conformance with 40 CFR Part 60, Appendix F. After initial certification, MRC shall also continue to implement all of the requirements of 40 CFR Part 60.13 and 40 CFR Part 60, Appendices B and F for the #3 Boiler SO_2/O_2 CEMS (ARM 17.8.749).

7. For both the gasoline truck loading rack and the gasoline railcar loading rack, MRC shall install, calibrate, certify, operate and maintain a thermocouple with an associated recorder as a continuous parameter monitoring system (CPMS). A CPMS shall be located in each VCU firebox or in the ductwork immediately downstream from the firebox in a position before any substantial heat exchange occurs in accordance with 40 CFR Part 63.427, in order to demonstrate compliance with 40 CFR 63, Subpart R. MRC shall operate the VCUs in a manner not to go below the operating parameter values established using the procedures in 40 CFR Part 63.425 (ARM 17.8.342 and 40 CFR 63, Subpart CC).

E. Emission Testing:

1. The FCCU shall be tested for CO and SO_2 and the results submitted to the Department in order to demonstrate compliance with the emission limits contained in Section II.C.9.c and d. The testing shall occur annually or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and ARM 17.8.106).

2. Compliance with the FCCU PM emission limit in Section II.C.9.a shall be demonstrated by conducting a 3-hour performance test representative of normal operating conditions for PM emissions by December 31 of each calendar year. If any performance test undertaken pursuant this section is not representative of normal operating conditions, MRC shall conduct a subsequent performance test representative of normal operating conditions by no later than 90 days after the test that was not representative (MRC Consent Decree).

3. The #1, #2, Boilers shall be tested for NOx and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the emission limits contained in Section II.C.2. The testing shall occur on an every 2 year basis or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and ARM 17.8.106).

4. MRC shall test the #3 Boiler, for CO and NOx concurrently, to monitor compliance with the emission limits and/or conditions contained in Section II.A.3 and Section II.C.3. The initial performance source test must be conducted within 60 days of achieving the maximum production rate, but not later than 180 days after initial startup of the boiler. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

5. MRC shall comply with all test methods and procedures as specified by 40 CFR Part 63, 63.425(a) through (c), and 63.425(e) through (h). This shall apply to, but not be limited to, the gasoline and distillate truck loading rack, the gasoline railcar loading rack, the vapor processing systems, and all gasoline equipment.

6. The gasoline truck loading rack VCU shall be tested for total organic compounds and compliance demonstrated with the emission limitation contained in Section II.C.7 on an every 5-year basis or according to another testing/monitoring schedule as may be approved by the Department. MRC shall perform the test methods and procedures as specified in 40 CFR Part 63.425 (ARM 17.8.105 and 17.8.342).

7. The gasoline railcar loading rack VCU shall be initially tested for total organic compounds and compliance demonstrated with the emission limitation contained in Section II.C.8.a within 180 days of initial start up. Additional testing shall occur on an every 5-year basis or according to another testing/monitoring schedule as may be approved by the Department. MRC shall perform the test methods and procedures as specified in 40 CFR Part 63.425 (ARM 17.8.105 and 17.8.342).

8. The gasoline railcar loading VCU shall be initially tested for CO and NOx, concurrently, and compliance demonstrated with the emission limitations contained in Section II.C.8.b and c within 180 days of initial startup (ARM 17.8.105).

9. Fuel flow rates, production information, and any other data the Department believes is necessary shall be recorded during the performance of source tests (ARM 17.8.749).

10. All compliance source tests shall be conducted in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

11. The Department may require further testing (ARM 17.8.105).

F. Compliance Determination:

1. Facility-wide Refinery:

   a. Compliance with the plant-wide SO_2 emission limitations contained in Section II.C.1.a shall be determined based on data taken from the refinery fuel gas H_2S monitoring systems required by 40 CFR 60, Subpart J, in conjunction with metered refinery fuel gas usage (including SWSOH, if appropriate), data from the FCCU, the #1 and #2 boiler SO_2 CEMS, the #3 Boiler SO_2 CEMs and stack testing data.

   b. Compliance with the plant-wide CO emission limitations contained in Section II.C.1.b shall be determined based on data from the FCCU CO CEMS and emission factors developed from stack tests of the #1 & #2 boiler, #3 boiler, FCCU, product loading VCUs, and any other stack tests conducted.

2. #1 & #2 Boilers

   a. Compliance with #1 and #2 boiler SO_2 emission limitations contained in Section II.C.2.a shall be based on the data from the SO_2/O_2 CEMS (MRC May 2008 Administrative Order on Consent and ARM 17.8.749).

   b. In the event that SO_2/O_2 CEMS is not operational, MRC must (ARM 17.8.749):

      i. notify the Department of the problem within 24 hours (by phone) followed by written notification within 7 days;

ii. continue to monitor using the H_2S CEMs at the fuel gas drum (pre-combustion);

iii. route all SWSOH to the NaHS unit;

iv. repair and/or replace the SO_2/O_2 CEMs equipment and continue to monitor compliance as required in Section II.F; and

v. notify the Department within 24-hours when the SO_2/O_2 CEMS is back on-line.

c. Compliance with the #1 and #2 Boiler NO_x emission limitations contained in Section II.C.2.b shall be determined based on actual fuel burning rates and the emission factor developed from the most recent compliance source test.

d. Compliance with the #1 & #2 boiler CO emission limitations contained in Section II.C.2.c shall be determined through compliance source testing and by using the actual fuel burning rates and the emission factors developed from the most recent compliance source test.

3. #3 Boiler

a. Compliance with the #3 Boiler SO_2 emission limitations contained in Section II.C.3 shall be based on the data from the SO_2/O_2 CEMS (ARM 17.8.749).

b. In the event that SO_2/O_2 CEMS is not operational, MRC must (ARM 17.8.749):

i. notify the Department of the problem within 24 hours (by phone) followed by written notification within 7 days;

ii. continue to monitor using the H_2S CEMs at the fuel gas drum (pre-combustion);

iii. route all SWSOH to the NaHS unit;

iv. repair and/or replace the SO_2/O_2 CEMs equipment and continue to monitor compliance as required in Section II.F.3;

v. notify the Department within when the SO_2/O_2 CEMS is back on-line.

c. Compliance with the NOx emission limit in Section II.C.3 for the #3 Boiler shall be demonstrated by conducting three, one-hour performance tests representative of normal operating conditions for NOx emissions by December 31st of each calendar year. If any performance test undertaken pursuant this section is not representative of normal operating conditions, MRC shall conduct a subsequent performance test representative of normal operating conditions by no later than 90 days after the test that was not representative. After three consecutive years of testing, MRC may request that the Department re-evaluate the testing requirement provided MRC has proposed adequate operating parameters for the unit that can be used as indicators of compliance (ARM 17.8.749 and MRC Consent Decree).

d. Compliance with the #3 Boiler CO emission limitations contained in Section II.C.3 shall be determined through compliance source testing and by using the actual fuel burning rates and the emission factors developed from the most recent compliance source test (ARM 17.8.749).

4. Diesel/Gas Oil HDS Heater

   Compliance determinations for NO_x and CO emission limits for the diesel/gas oil HDS heater shall be based upon actual fuel burning rates and emission factors developed from the most recent compliance source test.

5. Hydrogen Plant Reformer Heaters

   a. Compliance determinations for NO_x and CO emission limits for Hydrogen Plant #1 reformer heater shall be based upon actual fuel burning rates and the emission factors developed from the most recent compliance source test.

   b. Compliance with the NOx emission limit in Section II.C.6 for Hydrogen Plant #2 process heater shall be demonstrated by conducting three, one-hour performance test representative of normal operating conditions for NOx emissions by December 31 of each calendar year. If any performance test undertaken pursuant this section is not representative of normal operating conditions, MRC shall conduct a subsequent performance test representative of normal operating conditions by no later than 90 days after the test that was not representative. After three consecutive years of testing, MRC may request that the Department re-evaluate the testing requirement provided MRC has proposed adequate operating parameters for the unit that can be used as indicators of compliance (ARM 17.8.749 and MRC Consent Decree).

6. Gasoline Truck Loading Rack VCU

   Compliance determinations for VOC, NOx and CO emission limits for the gasoline truck loading rack VCU shall be based upon the most recent compliance source test as well as compliance with the designated operating parameter value using the thermocouple and recorder.

7. Gasoline Railcar Loading Rack VCU

   Compliance determinations for VOC, NOx and CO emission limits for the gasoline railcar loading rack VCU shall be based upon the most recent compliance source test as well as compliance with the designated operating parameter value using the thermocouple and recorder.

8. FCCU

   Compliance determinations for the PM emission limit under Section II.C.9.a will be based on the annual source test conducted under Section II.E. Compliance determinations for CO, SO_2 and NOx emission limits under Section II.C.9 will be based on the data from CEMS as well as the annual source test conducted under Section II.E.

9. Compliance with the opacity limitations shall be determined according to 40 CFR Part 60, Appendix A, and Method 9 Visual Determination of Opacity of Emissions from Stationary Sources.

G. Reporting and Recordkeeping Requirements:

1. Plant-wide Refinery

MRC shall provide quarterly emission reports to demonstrate compliance with Section II.C.1.a using data required in Section II.F.1.a. The quarterly report shall include the following (ARM 17.8.749):

a. Facility-wide SO_2 emission estimates for each month of the quarter, including:

- Refinery fuel gas: daily H2S monitoring data and refinery fuel gas usage;
- SWSOH: daily H_2S and SWSOH combustion amount, or SO_2 monitoring data from the #1 & #2 Boiler stack;
- SO_2 CEMS Data from FCCU, #1 and #2 Boiler, and #3 Boiler converted to daily mass emissions;

b. Compliance source test data used to update emission factors, conducted during the reporting period;

c. Identification of any periods of excess emissions or other excursions during the reporting period; and

d. Monitoring downtime that occurred during the reporting period.

2. #1 and #2 Boilers

MRC shall provide quarterly emission reports to demonstrate compliance with Section II.C.2 using data required in Section II.F.2. The quarterly report shall include the following (ARM 17.8.749):

a. SO_2 emission estimates for #1 and #2 Boilers, for each month of the quarter, including:

- Hourly SO_2 CEMS data for the reporting period;
- Fuel gas H_2S analyzer data for the reporting the period;
- SWSOH – either the daily H_2S concentration and SWSOH combustion amount of the HTU SWSOH, or the #1 & #2 Boiler stack SO_2 concentration on a daily basis;

b. NO_X emission estimates for each month of the quarter. The NO_X emission rates shall be reported as an hourly average;

c. CO emission estimates for the #1 and #2 Boilers, for each month of the quarter. The CO emission rate shall be reported as an hourly average;

d. Operating times for #1 and #2 Boilers and the HTU SWS unit during the reporting period;

e. Compliance source test data used to update emission factors, conducted during the reporting period;

f. Identification of any periods of excess emissions or other excursions during the reporting period; and

g. Monitoring downtime that occurred during the reporting period.

3. #3 Boiler

MRC shall provide quarterly emission reports to demonstrate compliance with Section II.C.3 using data required in Section II.F.3. The quarterly report shall include the following (ARM 17.8.749):

a. SO_2 emission estimates for the #3 Boiler, for each month of the quarter, including:

- Hourly SO_2/O_2 CEMS data for the reporting period;
- Fuel gas H_2S analyzer data for the reporting the data;
- SWSOH – either the daily H_2S concentration and SWSOH combustion amount of the HTU SWSOH, or the #3 Boiler stack SO_2 concentration on a daily basis;

b. NO_X emission estimates for each month of the quarter. The NO_X emission rates shall be reported as an hourly average;

c. CO emission estimates for the #3 Boiler, for each month of the quarter. The CO emission rate shall be reported as an hourly average;

d. Operating times for #3 Boiler and the HTU SWSOH unit during the reporting period;

e. Compliance source test data used to update emission factors, conducted during the reporting period;

f. Identification of any periods of excess emissions or other excursions during the reporting period; and

g. Monitoring downtime that occurred during the reporting period.

4. Gasoline Truck Loading Rack VCU

MRC shall comply with all recordkeeping and reporting requirements, as applicable, of 40 CFR Part 63.654 and the referenced provisions in 40 CFR 63, Subpart R (ARM 17.8.342 and 40 CFR 63, Subpart CC).

5. Gasoline Railcar Loading Rack VCU

MRC shall comply with all recordkeeping and reporting requirements, as applicable, of 40 CFR Part 63.654 and the referenced provisions in 40 CFR 63, Subpart R (ARM 17.8.342 and 40 CFR 63, Subpart CC).

6. FCCU

MRC shall provide quarterly emission reports to demonstrate compliance with Section II.C.9 using data required in Section II.F.8. The quarterly report shall include the following (ARM 17.8.749):

a. Emission estimates for NO_x, SO_2 and CO, for each month of the quarter;

b. Daily SO_2 CEMS data for the reporting period;

c. Hourly NO_x and CO CEMS data for the reporting period;

d. Operating times for the FCCU during the reporting period;

e. Identification of any periods of excess emissions or other excursions during the reporting period; and

f. Monitoring downtime that occurred during the reporting period.

7. All Emission Reports shall be submitted within 45 days following the end of the calendar quarter (ARM 17.8.749).

8. MRC shall maintain a file of all measurements from all CEMS and H_2S monitors, including, but not limited to: compliance data; performance testing measurements; all flow rate meter performance evaluations; all flow rate meter calibrations, checks, and audits. Adjustments and maintenance performed on these systems or devices shall be recorded in a permanent form suitable for inspection. The file shall be retained on site for at least 5-years following the date of such measurements and reports. MRC shall supply these records to the Department upon request (ARM 17.8.749).

H. Operational Reporting Requirements

1. MRC shall supply the Department with annual production information for all emission points, as required, by the Department in the annual Emission Inventory request. The request will include, but is not limited to, all sources of emissions identified in the Emission Inventory contained in the Permit Analysis and sources identified in Section I of this permit.

   Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the Emission Inventory request. Information shall be in the units required by the Department. This information may be used for calculating operating fees, based on actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

2. MRC shall notify the Department of any construction or improvement project conducted, pursuant to ARM 17.8.745, that would include a change of control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location, or fuel specifications, or would result in an increase in source capacity above its permitted operation or ***the addition of a new emission unit***. The notice must be submitted to the Department, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include information requested in ARM 17.8.745(l)(d) (ARM 17.8.745).

3. All records compiled in accordance with this permit must be maintained by MRC as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by the Department, and must be submitted to the Department upon request (ARM 17.8.749).

I. Notification Requirements

1. MRC shall provide the Department with written notification of the following dates within the specified time periods (ARM 17.8.749):

   a. Pretest information forms must be completed and received by the Department no later than 25 working days prior to any proposed test date, according to the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

   b. The Department must be notified of any proposed test date 10 working days before that date according to the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

   c. The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitations or can be expected to last for a period greater than 4 hours (ARM 17.8.110).

2. #3 Boiler

   a. Notification of start of construction of the #3 Boiler within 30 days after actual construction has begun; and

   b. Notification of the actual start-up date of the #3 Boiler within 15 days after the actual start-up of the unit.

J. Ambient Monitoring

MRC shall conduct ambient air monitoring as described in Attachment 1.

SECTION III: General Conditions

A. Inspection – MRC shall allow the Department's representatives access to the source at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment (Continuous Emissions Monitoring System (CEMS) and Continuous Emissions Rate Monitoring System (CERMS)) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.

B. Waiver – The permit and the terms, conditions, and matters stated herein shall be deemed accepted if MRC fails to appeal as indicated below.

C. Compliance with Statutes and Regulations – Nothing in this permit shall be construed as relieving MRC of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*. (ARM 17.8.756).

D. Enforcement – Violations of limitations, conditions and requirements contained herein may constitute grounds for permit revocation, penalties, or other enforcement action as specified in Section 75-2-401, *et seq*., MCA.

E. Appeals – Any person or persons jointly or severally adversely affected by the Department's decision may request, within 15 days after the Department renders its decision, upon affidavit setting forth the grounds therefore, a hearing before the Board of Environmental Review (Board). A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The filing of a request for a hearing does not stay the Department's decision, unless the Board issues a stay upon receipt of a petition and a finding that a stay is appropriate under Section 75-2-211(11)(b), MCA. The issuance of a stay on a permit by the Board postpones the effective date of the Department's decision until conclusion of the hearing and issuance of a final decision by the Board. If a stay is not issued by the Board, the Department's decision on the application is final 16 days after the Department's decision is made.

F. Permit Inspection – As required by ARM 17.8.755, Inspection of Permit, a copy of the air quality permit shall be made available for inspection by the Department at the location of the source.

G. Permit Fee – Pursuant to Section 75-2-220, MCA, as amended by the 1991 Legislature, failure to pay the annual operation fee by MRC may be grounds for revocation of this permit, as required by that section and rules adopted thereunder by the Board.

H. Duration of Permit – Construction or installation must begin or contractual obligations entered into that would constitute substantial loss within 3 years of permit issuance and proceed with due diligence until the project is complete or the permit shall expire (ARM 17.8.762).

Summary of Attachments

Attachment 1	AMBIENT AIR MONITORING PLAN

ATTACHMENT 1

AMBIENT AIR MONITORING PLAN
Montana Refining Company
Montana Air Quality Permit (MAQP) #2161-25

1. This Ambient Air Monitoring Plan is required by MAQP #2161-25, which applies to MRC's crude oil refinery located at 1900 10th Street North East, in Great Falls, Montana. The Department may modify the requirements of this monitoring plan. All requirements of this plan are considered conditions of the permit.

2. The requirements of this attachment shall take effect within 30 days of permit issuance, unless otherwise approved in writing by the Department.

3. MRC shall operate and maintain one air monitoring site northeast of the refinery. The exact location of the monitoring site must be approved by the Department and meet all the siting requirements contained in the Montana Quality Assurance Manual, including revisions, the EPA Quality Assurance Manual, including revisions, and 40 CFR Part 58, or any other requirements specified by the Department.

4. Within 90 days after issuance of MAQP #2161-25, MRC shall submit a topographic map to the Department identifying Universal Transverse Mercator (UTM) coordinates, air monitoring site locations in relation to the facility, and the general area present.

5. Within 30 days prior to any changes of the location of the ambient monitors, MRC shall submit a topographic map to the Department identifying UTM coordinates, air monitoring site locations in relation to the facility, and the general area present.

6. MRC shall continue air monitoring for at least 2 years after installation of the monitor described in Section 2 above. The Department will review the air monitoring data and the Department will determine if continued monitoring or additional monitoring is warranted. The Department may require continued air monitoring to track long-term impacts of emissions from the facility or require additional ambient air monitoring or analyses if any changes take place in regard to quality and/or quantity of emissions or the area of impact from the emissions.

7. MRC shall monitor the following parameters at the site and frequencies described below:

AIRS # 30-013-2001 Site Name – Race Track Site

UTM Coordinates	Code & Parameter	Frequency
Zone 12	42401 SO_2[1]	Continuous
N 5263700	61101 Wind Speed and Direction	"
E 478600	61106 Standard Deviation of Wind Direction (sigma theta)	"

[1]SO_2= sulfur dioxide

8. Data recovery for all parameters shall be at least 80% computed on a quarterly and annual basis. The Department may require continued monitoring if this condition is not met. (Data recovery = (Number of data points collected in evaluation period)/(number of scheduled data points in evaluation period)*(100%))

9. Any ambient air monitoring changes proposed by MRC must be approved, in writing, by the Department.

10. MRC shall utilize air monitoring and Quality Assurance (QA) procedures that are equal to or exceed the requirements described in the Montana Quality Assurance Manual, including revisions, the EPA Quality Assurance Manual, including revisions, 40 CFR Parts 50 and 58, and any other requirements specified by the Department.

11. MRC shall submit two hard copies of quarterly data reports within 45 days after the end of the calendar quarter and two hard copies of the annual data report within 90 days after the end of the calendar year.

12. The quarterly data submittals shall consist of a hard copy narrative data summary and a digital submittal of all data points in AIRS batch code format. The electronic data must be submitted to the Air Monitoring Section as digital text files readable by an office personal computer (PC) with a Windows operating system.

    The narrative data hard copy summary must be submitted to the Air Compliance Section and shall include:

    a. A hard copy of the individual data points,

    b. The first and second highest 24-hour rolling and block concentrations for SO_2,

    c. The first and second highest 3-hour concentrations for SO_2,

    d. The first and second highest hourly concentrations for SO_2,

    e. The quarterly and monthly wind roses,

    f. A summary of data completeness,

    g. A summary of the reasons for missing data,

    h. A precision data summary,

    i. A summary of any ambient air standard exceedances, and

    j. Quality Assurance/Quality Control (QA/QC) information such as zero/span/precision, calibration, audit forms, and standards certifications.

13. The annual data report shall consist of a narrative data summary. The narrative data hard copy summary must be submitted to the Air Compliance Section and shall include:

    a. A topographic map of appropriate scale with UTM coordinates and a true north arrow showing the air monitoring site location in relation to the refinery and the general area,

    b. The annual average concentration for SO_2;

    c. The year's four highest 24-hour rolling and block concentrations for SO_2,

    d. The year's four highest 3-hour concentrations for SO_2,

    e. The year's four highest hourly SO_2 concentrations,

f. The annual wind rose,

g. A summary of any ambient air standard exceedances, and

h. An annual summary of data completeness.

14. All records compiled in accordance with this Attachment must be maintained by MRC as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by the Department, and must be submitted to the Department upon request (ARM 17.8.749).

15. The Department may audit (or may require MRC to contract with an independent firm to audit) the air monitoring network, the laboratory performing associated analyses, and any data handling procedures at unspecified times.

16. The hard copy reports should be sent to:
    Department of Environmental Quality
    Attention: Air Compliance Section Supervisor

17. The electronic data from the quarterly monitoring shall be sent to:
    Department of Environmental Quality
    Attention: Air Monitoring Section Supervisor

Montana Air Quality Permit (MAQP) Analysis
Montana Refining Company
MAQP #2161-25

I. Introduction/Process Description

Montana Refining Company (MRC) operates a petroleum refinery located at the NE ¼ of Section 1, Township 20 North, Range 3 East, in Cascade County, Montana. The refinery is located along the Missouri River in Great Falls, Montana.

A. Permitted Equipment

The major permitted equipment at MRC includes:

Crude Unit
- Vacuum Heater
- Crude Furnace

Catalytic Poly Unit
Fluidized Catalytic Cracking Unit (FCCU)
- FCCU Preheater
- FCCU Regenerator

Catalytic Reformer Unit
- Reformer Heater
- Naphtha Heater
- Kerosene Heater
- Naphtha Hydrodesulfurization (HDS) Unit
- Kerosene HDS Unit

Alkylation Unit
- Deisobutanizer reboiler

Hydrogen Plants
- Hydrogen Plant Reformer #1
- Hydrogen Plant Reformer #2

Diesel/Gas Hydrotreater (HTU) Unit
Sodium Hydrosulfide (NaHS) Unit
Polymer-Modified Asphalt (PMA) Unit
- WT-1901 – wetting tank
- RT-1901 – reactor tank

Product Loading
- Truck Loading with Vapor Combustion Unit (VCU)
- Railcar Loading with VCU

Utilities
- Boilers #1 & #2
- Boiler #3
- Wastewater
- Cooling Towers

Storage Tanks, including:
- Heated Heavy Oil: #9, #50, #55, #56, #102, #110, #112, #130, #132, #133, #135, #137, #139 & #140
- Wastewater surge tank (installed in 2006)
- Light Oil: #52, #57, #122, #123, #125, #126
- Crude Oil: #124
- Heavy Oil: #36, #46, #47, #48, #53, #63

- Misc: Heavy Naphtha Tank #127; Heavy Oil Tanks #44, #45, #11; #2 Diesel Tank #116; Raw Diesel Tank #128; NaHS Product, Caustic Tank #35; Light Oil Tank #8, Ethanol Tank #175

B. Source Description

Petroleum refining has been conducted at this site since approximately 1920. MRC converts crude oil into a variety of petroleum products, including gasoline, diesel fuel, jet fuel, naphtha, asphalt, and NaHS.

C. Permit History

On December 2, 1985, the Montana Department of Health and Environmental Sciences and MRC signed a stipulation requiring MRC to obtain an air quality permit, and stipulated that a permit emission limitation of 4,700 tons per year (TPY) carbon monoxide (CO) would constitute compliance with ambient CO standards. MRC submitted this permit application with the intentions of permitting its existing refining operations, including all equipment not already permitted.

On October 20, 1985, MRC was granted a general permit for their petroleum refinery and major refinery equipment located in Great Falls, Cascade County, Montana. The application was given **MAQP #2161**.

The first alteration to their original permit was given **MAQP #2161-A** and was issued on May 31, 1989. This alteration involved the addition of a deisobutanizer reboiler.

The second alteration was given **MAQP #2161-A1** and was issued on March 12, 1990. This project involved the installation of one 30,000-barrel gasoline storage tank and one 40,000-barrel crude oil storage tank at the present facility. Both tanks were installed with external floating roof control.

The third alteration was given **MAQP #2161-A3** and was issued on December 18, 1990. This alteration consisted of the installation of a Hydrofluoric (HF) Acid Alkylation Unit, internal floating roofs at existing storage tanks, which had fixed roofs, and a safety flare.

The fourth alteration was given **MAQP #2161-04** and was issued on June 16, 1992. This alteration consisted of the installation of a NaHS unit at the existing Great Falls Refinery.

The NaHS unit receives refinery fuel gas (540,000 standard cubic foot per day (scf/day) maximum rated capacity) containing hydrogen sulfide (H_2S) and reacts with a sodium hydroxide caustic solution to remove virtually 100% of the H_2S by converting it to NaHS, a saleable product.

The resultant sweet fuel gas is burned, as before, in other process heaters. However, since the fuel gas contains virtually no H_2S, sulfur dioxide (SO_2) emissions from the process heaters, assuming no other changes, were decreased by nearly 60%. There was no decrease in permitted SO_2 emissions from this permit because the refinery wanted to retain the existing permitted SO_2 emission limitations so it could charge less expensive, higher sulfur crude oil.

In the basic process, off-gases from product desulfurizing processes (fuel gases) are contacted with a caustic solution in a gas contractor. The resultant reaction solution is continually circulated until the caustic solution is essentially used up; NaHS product is then sent to storage. Make-up caustic is added to the process as required. The process requires a gas contractor, process heat exchanger, circulation pump, storage tanks for fresh caustic and NaHS product, 12 pipeline valves, 4 open-ended valves, 21 flanges, and other process control equipment.

The only process emissions are fugitive Volatile Organic Compounds (VOC) from equipment (valves and flanges) in fuel gas stream service. To estimate unit VOC emissions, emission factors developed by the Environmental Protection Agency (EPA) for equipment in gas vapor service with measured emissions from 0 to 1,000 parts per million (ppm) are used. With an aggressive monitoring and maintenance program, fugitive VOC emissions from valves and flanges are within this 0 to 1,000-ppm range. Total annual fugitive VOC emissions from the NaHS units are estimated to be 20 pounds per year.

The tank that is to be used to store NaHS product was in jet fuel service. When taken out of jet fuel service, this tank (#35) is no longer a source of VOC emissions; the reduction in VOC emissions will be 2,270 pounds per year (PPY). Considering the 2,270-PPY decrease due to tank #35 service change, the refinery realized a net decrease in annual VOC emissions of 2,250 PPY or 1.1 TPY.

The fifth alteration was given **MAQP #2161-05** and was issued on October 15, 1992. This permit alteration was for the construction and operation of two 20,000-barrel capacity aboveground storage tanks at its Great Falls Refinery. The new tanks contain heavy naphtha (#127) and raw diesel (#128).

Each tank was constructed of metal sections welded together that rest on a concrete ring wall foundation. External floating roofs with dual seals are installed on each tank for VOC control.

On April 6, 1993, MRC was granted **MAQP # 2161-06** to construct and operate a HDS unit and hydrogen plant. This sixth alteration was required to go through New Source Review (NSR) - Prevention of Significant Deterioration (PSD) review for Oxides of Nitrogen (NO_X) and was deemed complete on February 22, 1993. The HDS project was designed to process 5,000 barrels per day (BPD) of diesel/gas oil and to reduce the sulfur content to 0.05 weight percent. The reduction of sulfur in diesel fuel and gasoline were mandated by the 1990 Clean Air Act Amendments and were accomplished by October 1993, and 1995, respectively. The desulfurizer unit operated by MRC was limited in size and throughput capacity to approximately 1,400 barrels per day.

The HDS project consisted of an HDS process unit and heater, hydrogen plant with reformer heater, and the removal of storage tanks #40 through #43. Tanks #40 and #41, which processed gas oil, were discontinued. Tanks #42 and #43 that process raw diesel were also discontinued. Tanks #44 and #111 were changed to gas oil use and Tank #45 which serviced JP-4 was changed to gas oil use.

On July 28, 1993, **MAQP #2161-07**, a modification to MRC's MAQP #2161-06, was issued to change the emission control requirements of the Section titled "Pressure Vessels."

In a system where the valves relieve to atmosphere, rupture discs can prevent emissions in the event of relief valve leakage. In HF systems, they can provide some protection from acid corrosion on the relief valve and acid salt formation. Except where HF acid is present, rupture discs do not provide any additional protection nor do they prevent any release of air contaminates in a closed relief system.

In heavy liquid service, rupture discs can be safety hazards by partial failure or leaking and changing, over time, the differential pressure required providing vessel protection. Therefore, only pressure vessels in HF Acid service shall be equipped with rupture discs upstream of the relief valves and all except storage tanks shall be vented to the flare system.

Also, the allowable particulate emission limitation for MRC's FCCU was corrected to reflect the maximum allowable emissions based on the process weight rule (Administrative Rules of Montana (ARM) 17.8.310). The maximum allowable emissions were calculated to be 234.53 TPY using a catalyst circulation rate of 125 tons per hour (TPH).

MRC requested a permit modification, **MAQP #2161-08**, to remove the alkylation unit and tanks #127 and #128 from New Source Performance Standards (NSPS) status because they were erroneously classified as affected facilities under NSPS when originally permitted. This request for modification was submitted on August 11, 1993, and issued on January 6, 1994.

When MRC applied for the preconstruction permit to build the HF Alkylation Unit in 1990, it was presumed, since this unit was new to MRC, it automatically fell under NSPS as new construction. Subsequently, it has been determined that if a source is moved as a unit from a location where operation occurred (Garden City, Kansas) to another location, it must meet the definition of reconstruction or modification in order to trigger NSPS applicability.

The alkylation plant was originally constructed in Garden City, Kansas during 1959 - 1960 and moved, in its entirety, to Great Falls and installed. Since the unit was originally constructed before the NSPS-affected date of January 5, 1981, it does not meet the criteria for construction date of a new source under 40 Code of Federal Regulations (CFR), Subpart GGG or Subpart QQQ.

The project did not meet the criteria under reconstruction because no capital equipment was replaced when the unit was relocated. The replacement work performed, as the unit was moved, amounted to pump seals, valve packing, bearings, small amounts of corroded piping, and some heat exchanger tubes and bundles, all of which are done routinely as maintenance. The VOC emitters, such as valve packing and pump seals, were upgraded to meet Best Available Control Technology (BACT).

Along the same line, tanks #127 and #128 were originally constructed at Cody, Wyoming in 1960 and relocated to Great Falls in 1993. The only change was the modification of the roof seals to double seals to meet BACT. This cost of modification was a total of $15,000 for both tanks as compared to more than $500,000 if two new tanks were to be built.

Also, on October 28, 1993, MRC submitted a permit application to alter the existing permit. This modification and alteration of the existing permits were assigned MAQP #2161-08. MRC proposed to construct and operate a 3,500 barrel-per-day asphalt polymerization unit. The unit enabled MRC to produce a polymerized asphalt product that would meet future federal specifications for road asphalt, as well as supply polymerized asphalt to customers that wished to use the product.

The proposed unit consisted of two circuits: the asphalt circuit and the hot oil circuit. In the asphalt circuit, polymerization occurs in a 1,000-barrel steel, vented mix tank. Product blending and storage occurs in 3 steel, vented 1,000 barrel tanks identified as A, B, and C. Existing Tanks #55 and #56 (3,000 barrels each) remained in asphalt service and are used for storage. In addition to the above equipment, the asphalt circuit also consisted of 4 pumps and approximately 47 standard valves. All the above equipment became part of the asphalt service and, except for Tanks #55 and #56, was new.

To maintain the asphalt at the optimum temperature in the storage and blending tanks, a hot circuit was utilized. Hot oil (heavy fuel oil) was heated in an existing permitted process heater (Tank #56 heater) and circulated through coils in the process tankage. No change in the method of operation of the heater was anticipated. A steel, vented hot-oil storage/supply tank was utilized to maintain the required amount of hot oil in the unit. In addition to the process heater and storage/supply tank, the hot-oil circuit consisted of one pump and approximately 56 standard valves. The above equipment was used in hot-oil service and, except for the heater, was new.

An annual emissions increase of 7.3 TPY of VOC was expected due to operation of the unit. It was anticipated that the unit would be operated only 6 months of the year. The VOC emissions resulted from the vented hot-oil tank and the valves and pump in hot-oil service.

MAQP #**2161-09** was issued on September 6, 1994, and included a change in the method of heating three previously permitted polymer modified asphalt tanks. As previously permitted, these tanks were heated utilizing circulating hot oil. The tanks were heated individually using natural gas fired fire-tube heaters. The use of natural gas eliminated the hot-oil circuit, including the hot-oil storage tank, entirely.

Since the initial permit application for the modified asphalt unit, several small design changes occurred involving the addition of a new 800-gallon wetting tank for asphalt service. An output line from existing Tank #69 (Tall Oil) was also added. This output line added approximately 12 new valves and one new pump, all in Tall Oil service, to the unit. All other valves and pumps were designated to be in asphalt service.

All VOC emissions from equipment and tanks in asphalt service were assumed to be negligible, since asphalt has negligible vapor pressure at the working temperatures seen in the unit.

MAQP #**2161-10**, for the installation of an additional boiler (Boiler #3) to provide steam for the facility, was never issued as a final permit. On May 28, 1997, the Department of Environmental Quality – Air Resources Management Bureau (Department) received a letter requesting the withdrawal of the permit application and the withdrawal was granted to MRC. A summary of this permitting action is included in the analysis for MAQP #2161-11.

MAQP #**2161-11** was issued on January 23, 1998, for the installation of a vapor collection system and enclosed flare for the reduction of Hazardous Air Pollutants (HAP) resulting from the loading of gasoline. This was done in order to comply with the gasoline loading rack provisions of 40 CFR 63, Subpart CC - National Emission Standards (NES) for Petroleum Refineries. A VCU was added to the truck loading rack. The gasoline vapors are collected from the trucks during loading then routed to an enclosed flare where combustion occurs. The result of this project was an overall reduction in the amount of VOC and HAPs emitted, and a slight increase in CO and NO_x emissions.

Because MRC's bulk gasoline and distillate truck loading rack VCU was defined as an incinerator under Montana Code Annotated (MCA) 75-2-215, a determination that the emissions from the VCU would constitute a negligible risk to public health was required prior to the issuance of a permit to the facility. MRC and the Department identified the following HAPs from the flare that was used in the health risk assessment. These constituents are typical components of MRC's gasoline.

1. Benzene
2. Toluene
3. Ethyl Benzene
4. Xylenes
5. Hexane
6. 2,2,4-Trimethlypentane
7. Cumene
8. Napthalene
9. 1,3-Butadiene

The reference concentrations for Benzene, Toluene, Ethyl Benzene, and Hexane were obtained from EPA's IRIS database. The risk information for the remaining HAPs was contained in the January 1992 CAPCOA Risk Assessment Guidelines. The ISCT3 modeling performed by MRC for HAPs identified above demonstrated compliance with the negligible risk requirement.

MRC requested, via a letter dated August 13, 1997, changes to administratively and technically correct MAQP #2161-09. These changes were necessary as a result of the withdrawal of MAQP #2161-10. The changes included correctly stating opacity limits relating to asphalt storage tanks, removing references to procedural rules, changing monitoring requirements for the HTU Sour Water Stripper (SWS) and changing performance specifications for the continuous H_2S monitoring system.

The Department issued Draft Modification #2161-11 on November 6, 1997, to address the permit changes that were requested by MRC. The Department received comments on November 13, 1997, from MRC and later met on November 17, 1997, to discuss the draft modification. Because MRC had applied for a permit alteration on October 21, 1997, for the loading rack VCU, the draft modification was addressed in the permit alteration request.

The Department issued Preliminary Determination #2161-11 on November 26, 1997. The Department received comments from MRC on December 4, 1997, December 10, 1997, December 15, 1997, and December 30, 1997. The Department responded to these comments via faxes on December 8, 1997, December 11, 1997, and December 16, 1997. On December 23, 1997, the Department was prepared to issue a Department Decision, but MRC requested, via telephone, that the decision not be issued until after the holidays. The decision was required to be issued by January 8, 1998, to meet the mandated time frames for issuing a Department Decision.

MAQP #2161-12 was not issued. MRC applied for a modification on February 18, 1998, and this action was given #2161-12. On February 27, 1998, the Department notified MRC that the permitting actions requested would require an alteration and that a complete preconstruction permit application would be required.

MAQP #2161-13 placed enforceable emission limits on the facility, both plant-wide and the #1 and #2 boilers. The emission limits showed, through the use of EPA-approved models, to protect the National Ambient Air Quality Standards (NAAQS) for SO_2. The continuous gas flowmeters installed on the vacuum heater and the crude heater were placed in the permit. Also, the #1 and #2 boiler limits were updated to allow MRC more flexibility in their operations. The limits were originally placed on the boilers to keep MRC below the PSD permitting threshold. The new limits maintained MRC's status below the PSD permitting threshold.

The monitoring location was identified in Attachment 1 Ambient Air Monitoring Plan. The current location was determined to be inappropriate after reviewing the modeling analysis, and the new location was approximately 1.2 km from its present location. The monitoring location was chosen based on the modeling analysis that was submitted and is required to provide monitored confirmation of compliance with the Montana SO_2 Standards.

The method numbers for examination of water and wastewater were updated. The conditions in MAQP #2161-13 were incorporated into the Operating Permit and the compliance demonstration methodology for those conditions was evaluated at the time of the Operating Permit's issuance. MAQP #2161-13 replaced MAQP #2161-11.

On August 4, 2001, the Department issued **MAQP #2161-14** for the installation and operation of five 1600-kilowatt (kW) diesel-powered, temporary generators. These generators were necessary because of the current high cost of electricity. The generators would only operate for the length of time necessary for MRC to acquire a permanent, more economical, supply of power. Further, the generators are limited to a maximum operating period of 2 years.

Because these generators would only be used when commercial power is cost prohibitive, the amount of emissions expected during actual operation is minor. In addition, because the permit limits the operation of these generators to a time period of less than 2-years, the installation and operation qualifies as a "temporary source" under the PSD permitting program. Therefore, the proposed project does not require compliance with ARM 17.8.804, 17.8.820, 17.8.822, and 17.8.824. Even though the portable generators are considered temporary, the Department requires compliance with BACT and public notice requirements; therefore, compliance with ARM 17.8.819 and 17.8.826 will be ensured. Finally, MRC is responsible for complying with all applicable ambient air quality standards. MAQP #2161-14 replaced MAQP #2161-13.

On August 17, 2002, the Department issued **MAQP #2161-15** to eliminate the summer boiler SO_2 emission limits (both the plant-wide and 24-hour average) and redefine the winter limits as year-round limits. The seasonal limits were originally placed in the permit to allow MRC more flexibility when operating the boilers. Both the winter and summer scenarios were supported by ambient air quality modeling performed prior to MAQP #2161-13 being issued. The winter limit being redefined as a year-round limit does not represent an increase in SO_2 emissions from the boilers or any other emitting point. In addition, the Department removed requirements to determine and report NO_X emissions both from the crude heater (due to the old SWS) and refinery wide, as these sources are not subject to NO_X emissions limitations. The requirements appeared to have been inadvertently applied through an administrative error. MRC already provides refinery-wide NO_X emissions as part of its annual Emission Inventory submission to the Department. MAQP #2161-15 replaced MAQP #2161-14.

On March 19, 2003, the Department issued **MAQP #2161-16** to include certain limits and standards associated with the Consent Decree lodged on December 20, 2001. In addition, the permit was updated with new rule references under ARM 17.8, Subchapter 7. MAQP #2161-16 replaced MAQP #2161-15.

The Department received a request to modify MAQP #2161-16 on July 10, 2003, to change the emission testing schedule for the gasoline truck loading vapor combustion unit to be consistent with MRC's current operating permit. MRC also requested the Department clarify the 7,000-BPD limit of crude charge (referenced in MRC's Title V Operating Permit) is no longer valid. Should MRC's normal processing exceed 7,000-BPD, MRC would be required to comply with ARM 17.8.324, as applicable. In a letter received by the Department on September 30, 2003, MRC also requested to add three new asphalt tanks with associated natural gas heaters. The emissions from the three tanks met the requirements of the de minimis rule and were added to the permit. The current permit action updated the permit to reflect the changes. **MAQP #2161-17** replaced MAQP #2161-16.

On May 14, 2004, the Department received a letter from MRC requesting changes to MAQP #2161-17. The proposed change includes adding the ability to burn sweet gas in heaters at the HF Alkylation Unit, and at Tanks 102, 135, 137, 138, and 139. The sweet gas will have a H_2S limit equivalent to the 40 CFR Part 60, Standards of Performance for NSPS, Subpart J limit of 0.10 grains per dry standard cubic foot (gr/dscf) H_2S. The continuous refinery fuel gas monitoring system for H_2S installed on the fuel gas system that supplies the heaters would be used to determine compliance with the limit. Since the emissions from switching the fuel to sweet gas were less than the de minimis threshold, the Department added the fuel switch. . The current permit action updated the permit to reflect these changes. **MAQP #2161-18** replaced MAQP #2161-17.

On May 17, 2007, the Department received an application from MRC for the installation of a railcar product loading rack controlled by a John Zink VCU. On June 19, 2007, MRC clarified that gasoline and naphtha were the only products that will go through the new railcar loading rack, and that other liquid products already loaded into railcars (diesel, jet fuel, etc.) would not be affected.

The gasoline railcar loading rack is subject to 40 CFR 63, Subpart CC, which requires MRC to comply with specific bulk loading requirements in 40 CFR 63, Subpart R. Subpart R restricts the operation of the railcar loading system to less than 10 milligrams (mg) of VOC per liter of gasoline loaded and requires the operation of a continuous monitor downstream from the firebox. Furthermore, the gasoline and naphtha railcars are considered as 'gasoline cargo tanks' and are required to comply with the leak detection testing requirements. Lastly, 40 CFR 63, Subpart CC requires MRC to comply with 40 CFR 60, Subpart VV to minimize fugitive equipment leaks.

Other new applicable regulations were added, including 40 CFR 63, Subpart UUU, Subpart EEEE, and Subpart DDDDD. Consent Decree #CIV-01-1422LH requirements, entered March 5, 2002 (MRC Consent Decree), were included, such as the new requirements to comply with 40 CFR 60, Subpart J limits for refinery fuel gas and SWSOH. Other changes completed in this permit action were: adding FCCU uncorrected CO emissions from 40 CFR 63, Subpart UUU, and SO_2 and NO_X emission limits resulting from the Consent Decree; and revising the permit to reflect the operation of a continuous H_2S fuel gas meter and requirement to comply with 40 CFR 60, Subpart J. **MAQP #2161-19** replaced MAQP #2161-18.

On October 15, 2007, the Department received letter from MRC requesting a correction to MAQP #2161-19, to remove the restrictions on the type of fuel used in specific asphalt tank heaters, which was added erroneously during the previous permitting action. In addition, the MAQP was updated to reflect the fact that requirements under 40 CFR 63, Subpart DDDDD are now "state-only" since the federal rule was vacated in Federal Court on July 30, 2007. **MAQP #2161-20** replaced MAQP #2161-19.

On June 9, 2008, the Department received a letter from MRC requesting an amendment to MAQP #2161-20, to modify the restrictions on Storage Tank #8. This request was a follow-up to a de minimis request received by the Department on April 21, 2008, where MRC proposed to change the operation of Storage Tank #8 from NaHS to naphtha. The Department reviewed this de minimis request and determined that MAQP #2161-20 must first be amended as described in the ARM 17.8.745(2) and ARM 17.8.764 before this change would be allowed. Although the potential emissions increase for this project is less than the de minimis threshold, the proposal would have violated a condition of MRC's current permit. Specifically, the MAQP states, "Storage tanks #8, #9, #50, #55, #56, #69 #102, #110, #112, #130, #132, #133, and #135 shall be used for asphalt, modified asphalt, or tall oil service (ARM 17.8.749)." This permit has been amended to allow the proposed change in operation of Storage Tank #8.

On July 2, 2008, the Department received another letter from MRC requesting an administrative amendment to MAQP #2161-20 to include certain conditions specified in the Administrative Order on Consent (AOC) that MRC entered into with the Department on May 13, 2008. The AOC requires MRC to install and operate a SO_2 and Oxygen (O_2) continuous emission monitor system (CEMS) on the stack for the #1 and #2 Boilers. This SO_2/O_2 CEMS is to be used as the primary analytical instrument to determine compliance with state and federal SO_2 requirements. The AOC requires MRC to request that these conditions be included in the MAQP as enforceable permit conditions.

In addition, MRC requested that the permit be amended to allow certain de minimis changes related to the Diesel/Gas Oil HDS heater and three PMA tank heaters. Specifically, MRC requested that refinery fuel gas, in addition to natural gas, be allowed to be burned in these heaters. The current permit requires that the Diesel/Gas Oil HDS heater and the three PMA tank heaters be fired only with natural gas. This requirement is based on BACT. For the Diesel/Gas Oil HDS heater, the BACT analysis requires that low sulfur fuel be used. Since the refinery fuel gas is also a low sulfur fuel meeting 40 CFR 60, Subpart J requirements of 160 ppm H_2S, the Department determined that the proposed change does not violate any applicable rule and therefore, can be allowed through an administrative amendment as specified in ARM 17.8.745(2) and ARM 17.8.764. For the three PMA tank heaters, however, the BACT analysis specifically requires that these heaters be fired with natural gas for control of NO_x emissions. Therefore, the Department determined that the proposed three PMA tank heaters de minimis changes are prohibited under ARM 17.8.745(1)(a)(i) since an applicable rule, specifically ARM 17.8.752 requiring that BACT be utilized, would be violated. Because BACT determinations cannot be changed under the amendment process, the Department requested that MRC submit an application for a permit modification that would include a revised BACT analysis in order to make the proposed change for the three PMA tank heaters.

In addition, the Department updated Attachment 1 to reflect the most current permit language and requirements for ambient monitoring. **MAQP #2161-21** replaced MAQP #2161-20.

On December 19, 2008, the Department received a request from MRC to amend MAQP #2161-21. MRC requested to change the wording for material stored in specified storage tanks to language representative of the requirements of 40 CFR 60, Subpart Kb in order to provide operational flexibility. Instead of referring to specific products (e.g., naptha, gasoline, diesel, tall oil, etc.), the products would instead be referred to as light oils, medium oils, and heavy oils.

Under MRC's proposed language, light oils would be defined as a volatile organic liquid with a maximum true vapor pressure greater than or equal to 27.6 kilopascal (kPa), but less than 76.6 kPa and would include, but not be limited to, gasoline and naptha. Medium oils would be defined as volatile organic liquids with a vapor pressure less than 27.6 kPa and greater than or equal to 5.2 kPa and would include, but not be limited to, ethanol. Heavy oils would be defined as volatile organic liquid with a maximum true vapor pressure less than 5.2 kPa and would include, but not be limited to diesel, kerosene, jet fuel, slurry oil, and asphalt.

In addition to making the requested change, the Department has clarified the permit language for the bulk loading rack VCU regarding the products that may be loaded in the event the VCU is inoperable and deleted all references to 40 CFR 63, Subpart DDDDD: NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters, as it was removed from the ARM in October 2008. The Department has also updated Attachment 1, Ambient Monitoring to reflect the most current permit language and requirements for ambient monitoring. **MAQP #2161-22** replaced MAQP #2161-21.

On July 9, 2009, the Department received a permit application from MRC to modify MAQP #2161-22. The application was deemed complete on July 24, 2009. MRC submitted a permit modification to allow the use of treated refinery fuel gas or natural gas in the tank heaters. Previously, the PMA tanks heaters were permitted to use natural gas only pursuant to a BACT analysis that was completed for MAQP #2161-09. This permit modification applied to three previously permitted asphalt tanks (Tanks #130, 132 and 133) and the associated PMA tank heaters. **MAQP #2161-23** replaced MAQP #2161-22.

On January 15, 2008, the Department received a request from MRC to install a second hydrogen plant that utilizes a process heater with a heat input of 80 million British thermal units per hour (MMBtu/hr). The Department approved this de minimis request on February 8, 2008. Pursuant to the Consent Decree (CD) and the approval of the de minimis request, MRC was required to conduct an initial performance test on the process heater with the results reported based upon the average of three, one hour testing periods. The CD also required MRC to submit an application to the Department and to propose an NO_x permit limit for the heater. MRC submitted a permit application on December 29, 2009 and the Department deemed this application incomplete on January 15, 2010. On July 12, 2010, MRC submitted additional information as requested by the Department. On September 2, 2010, during the comment period, MRC submitted information to support the guaranteed ultra low NO_x burner emission limit of 0.033 lb/MMBtu based on the Higher Heating Value (HHV) of the fuel. This limit was based on the process heater of the hydrogen plant operating at full capacity (80 MMBtu/hr) with fuel gas consisting of 40.5 % natural gas and 59.4% PSA vent gas. This permit modification applies to NO_x limits on the Hydrogen Plant #2 process heater. **MAQP #2161-24** replaced MAQP #2161-23.

D. Current Permit Action

On July 6, 2011, MRC submitted a permit application and subsequent modeling demonstration to add a new boiler (the #3 Boiler) capable of firing refinery fuel gas, SWSOH, or natural gas at the petroleum refinery. The primary purpose of the #3 Boiler is to supplement the two existing boilers (#1 and #2) that provide process steam to the refinery. The design burner heat input capacity for the #3 Boiler varies, depending upon fuel characteristics, from 59.7 to 60.5 MMBtu/hr. The Department deemed the application incomplete on August 4, 2011, and MRC provided additional information in response to the Department's letter on September 26, 2011.

On October 25, 2011, the Department requested additional information with respect to MRC's plantwide applicability limit (PAL) and the SWSOH combustion properties. This information was received by the Department on November 15, 2011. Additionally, because MRC experiences significant downtime with the SO_2/O_2 CEMs required on the #1 and #2 Boiler stack, MRC submitted a request to allow the use of the H_2S fuel gas analyzer located near the fuel gas drum as backup to the SO_2/O_2 CEMs. MRC also requested this for the #3 Boiler.

Therefore in addition to adding the #3 Boiler to the refinery's operation, the current permit action also adds compliance, reporting and recordkeeping requirements for allowing the H_2S fuel analyzer to be used as a back up to the SO_2/O_2 CEMS. When the H_2S fuel analyzer is used, MRC would not be allowed to route the SWSOH to the boilers. **MAQP #2161-25** replaces MAQP #2161-24.

E. Additional Information

Additional information, such as applicable rules and regulations, BACT/Reasonably Available Control Technology (RACT) determinations, air quality impacts, and environmental assessments, is included in the analysis associated with each change to the permit.

II. Applicable Rules and Regulations

The following are partial explanations of some applicable rules and regulations that apply to the facility. The complete rules are stated in the ARM and are available upon request from the Department. Upon request, the Department will provide references for locations of complete copies of all applicable rules and regulations or copies where appropriate.

A. ARM 17.8, Subchapter 1 – General Provisions, including, but not limited to:

1. ARM 17.8.101 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.105 Testing Requirements. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the Department, provide the facilities and necessary equipment, including instruments and sensing devices, and shall conduct tests, emission or ambient, for such periods of time as may be necessary, using methods approved by the Department. MRC shall also comply with the testing and monitoring requirements of this permit.

3. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by the Department, any source, or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Clean Air Act of Montana, 75-2-101, *et seq*., MCA.

4. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by the Department, any source, or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Clean Air Act of Montana, 75-2-101, *et seq*., MCA.

5. MRC shall comply with all requirements contained in the Montana Source Test Protocol and Procedures Manual, including, but not limited to, using the proper test methods and supplying the required reports. A copy of the Montana Source Test Protocol and Procedures Manual is available from the Department upon request.

6. ARM 17.8.110 Malfunctions. (2) The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation or to continue for a period greater than 4 hours.

7. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means that, without resulting in reduction in the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant that would otherwise violate an air pollution control regulation. (2) No equipment that may produce emissions shall be operated or maintained in such a manner as to create a public nuisance.

B. ARM 17.8, Subchapter 2 – Ambient Air Quality, including, but not limited to the following:

1. ARM 17.8.204 Ambient Air Monitoring
2. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide
3. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide
4. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide
5. ARM 17.8.213 Ambient Air Quality Standard for Ozone
6. ARM 17.8.214 Ambient Air Quality Standard for Hydrogen Sulfide
7. ARM 17.8.220 Ambient Air Quality Standard for Settled Particulate Matter
8. ARM 17.8.221 Ambient Air Quality Standard for Visibility
9. ARM 17.8.222 Ambient Air Quality Standard for Lead
10. ARM 17.8.223 Ambient Air Quality Standard for PM_{10}

MRC must maintain compliance with the applicable ambient air quality standards.

C. ARM 17.8, Subchapter 3 – Emission Standards, including, but not limited to:

1. ARM 17.8.304 Visible Air Contaminants. (1) This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed on or before November 23, 1968, that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes. (2) This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.

2. ARM 17.8.308 Particulate Matter, Airborne. (1) This rule requires an opacity limitation of less than 20% for all fugitive emission sources and that reasonable precautions be taken to control emissions of airborne particulate matter. (2) Under this rule, MRC shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter.

3. ARM 17.8.309 Particulate Matter, Fuel Burning Equipment. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter caused by the combustion of fuel in excess of the amount determined by this rule.

4. ARM 17.8.310 Particulate Matter, Industrial Process. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter in excess of the amount set forth in this rule.

5. ARM 17.8.322 Sulfur Oxide Emissions – Sulfur in Fuel. (5) Commencing July 1, 1971, no person shall burn any gaseous fuel containing sulfur compounds in excess of 50 grains per 100 cubic feet of gaseous fuel, calculated as hydrogen sulfide at standard conditions. MRC is a small refinery (under 10,000 BPD crude oil charge) and is, therefore, exempt from this rule, provided that they meet the other provisions of this rule.

6. ARM 17.8.324 Hydrocarbon Emissions – Petroleum Products. (3) No person shall load or permit the loading of gasoline into any stationary tank with a capacity of 250 gallons or more from any tank truck or trailer, except through a permanent submerged fill pipe, unless such tank is equipped with a vapor loss control device as described in (1) of this rule. MRC is subject to this rule when MRC's normal processing exceeds 7,000 bbl/day of crude charge.

7. ARM 17.8.340 Standard of Performance for New Stationary Sources. This rule incorporates, by reference, 40 CFR Part 60, NSPS. The owner or operator of any stationary source or modification, as defined and applied in 40 CFR Part 60, shall comply with the standards and provisions of 40 CFR Part 60, NSPS. The applicable NSPS Subparts include, but are not limited to:

   a. Subpart A – General Provisions apply to all equipment or facilities subject to an NSPS Subpart as listed below.

   b. Subpart Dc – Standards of Performance for Small Industrial-Commercial Insitutional Steam Generating Units for which construction, modification, or reconstruction is commenced after June 9, 1989. This Subpart would apply to the #3 Boiler.

   c. Subpart J – Standards of Performance for Petroleum Refineries. This Subpart applies to facilities that are constructed or modified after June 11, 1973; therefore, new and modified fuel gas combustion devices will be subject to the provisions of Subpart J. In addition, the following shall apply, as described per the MRC Consent Decree:

      i. FCCU regenerator: for CO and for SO_2, and
      ii. Heaters and boilers.

   d. Subpart Ja – Standards of Performance for Petroleum Refineries for which Construction, Reconstruction or Modification Commenced After May 14, 2007. This Subpart applies to facilities that are constructed or modified after May 14, 2007. The #3 Boiler meets the applicability requirements of this Subpart; however, requirements for fuel gas combustion devices have been stayed until further notice.

e. Subpart Kb – Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction or Modification Commenced After July 23, 1984.

Note: The five tanks used in the PMA unit, listed below, are exempt from the provisions of Subpart Kb because the true vapor pressure (TVP) of the Volatile Organic Liquid (VOL) stored is less than 3.5 kilopascals (Kpa) (0.5076 pounds per square inch atmosphere (psia)).

	PMA Unit	
Tank	Capacity	TVP (psia)
WT-1901 wetting tank	800 gal	negligible
RT-1901 reactor tank	715 bbl	negligible
asphalt storage (3)	1,000 bbl	negligible

f. Subpart UU – Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture – shall apply to all asphalt storage tanks that process and store only non-roofing asphalts, and was constructed or modified since May 26, 1981.

g. Subpart GGG – Equipment Leaks of VOC in Petroleum Refineries shall not apply to the following units:

Equipment	Year of Mfg.	Year of Install.
HF Alkylation Unit	1960	1990

h. Subpart QQQ – VOC Emissions from Petroleum Refinery Wastewater Systems does not apply to the following units:

Equipment	Year of Mfg.	Year of Install.
HF Alkylation Unit	1960	1990

i. All other applicable subparts and referenced test methods.

8. ARM 17.8.342 Emission Standards for Hazardous Air Pollutants for Source Categories. The source, as defined and applied in 40 CFR Part 63, shall comply with the requirements of 40 CFR Part 63, as listed below:

a. Subpart A – General Provisions applies to all National Emission Standards for Hazardous Air Pollutants (NESHAP) source categories subject to a Subpart as listed below.

b. Subpart R – NESHAP for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations), applies as specified under Subpart CC.

c. Subpart CC – NESHAP Pollutants from Petroleum Refineries shall apply to, but not be limited to, the bulk loading racks.

d. Subpart UUU – NESHAP Pollutants from Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Plants, shall apply to, but not be limited to, the FCCU and the Catalytic Reformer Unit.

e. Subpart EEEE – NESHAP for Organic Liquids Distribution (non-gasoline) shall apply to, but not be limited to, Tank #1 (DEGME) and the naphtha loading racks.

D. ARM 17.8, Subchapter 4 – Stack Height and Dispersion Techniques, including, but not limited to:

1. ARM 17.8.401 Definitions. This rule includes a list of definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.402 Requirements. MRC must demonstrate compliance with the ambient air quality standards based on the use of Good Engineering Practices (GEP) stack height.

E. ARM 17.8, Subchapter 5 – Air Quality Permit Application, Operation, and Open Burning Fees, including, but not limited to:

1. ARM 17.8.504 Air Quality Permit Application Fees. This rule requires that an applicant submit an air quality permit application fee concurrent with the submittal of an air quality permit application. A permit application is incomplete until the proper application fee is paid to the Department. MRC submitted the appropriate permit application fee for the current permit action.

2. ARM 17.8.505 Air Quality Operation Fees. An annual air quality operation fee must, as a condition of continued operation, be submitted to the Department by each source of air contaminants holding an air quality permit (excluding an open-burning permit) issued by the Department. The air quality operation fee is based on the actual or estimated actual amount of air contaminants emitted during the previous calendar year.

3. An air quality operation fee is separate and distinct from an air quality permit application fee. The annual assessment and collection of the air quality operation fee, described above, shall take place on a calendar-year basis. The Department may insert into any final permit issued after the effective date of these rules, such conditions as may be necessary to require the payment of an air quality operation fee on a calendar-year basis, including provisions that prorate the required fee amount.

F. ARM 17.8, Subchapter 7 – Permit, Construction, and Operation of Air Contaminant Sources, including, but not limited to:

1. ARM 17.8.740 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit modification to construct, modify, or use any air contaminant sources that have the Potential to Emit (PTE) greater than 25 tons per year of any pollutant. MRC has a PTE greater than 25 tons per year of PM, NO_X, CO, VOC, and SO_2; therefore, an air quality permit is required.

3. ARM 17.8.744 Montana Air Quality Permits--General Exclusions. This rule identifies the activities that are not subject to the Montana Air Quality Permit program.

4. ARM 17.8.745 Montana Air Quality Permits--Exclusion for De Minimis Changes. This rule identifies the de minimis changes at permitted facilities that do not require a permit under the Montana Air Quality Permit Program.

5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. (1) This rule requires that a permit application be submitted prior to installation, modification or use of a source. MRC submitted the required permit application for the current permit action. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. MRC submitted an affidavit of publication of public notice for the July 11, 2011, issue of the *Great Falls Tribune*, a newspaper of general circulation in the city of Great Falls, in Cascade County, as proof of compliance with the public notice requirements.

6. ARM 17.8.749 Conditions for Issuance or Denial of Permit. This rule requires that the permits issued by the Department must authorize the construction and operation of the facility or emitting unit subject to the conditions in the permit and the requirements of this subchapter. This rule also requires that the permit must contain any conditions necessary to assure compliance with the Federal Clean Air Act (FCAA), the Clean Air Act of Montana, and rules adopted under those acts.

7. ARM 17.8.752 Emission Control Requirements. This rule requires a source to install the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. The required BACT analysis is included in Section III of this Permit Analysis.

8. ARM 17.8.755 Inspection of Permit. This rule requires that air quality permits shall be made available for inspection by the Department at the location of the source.

9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving MRC of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*.

10. ARM 17.8.759 Review of Permit Applications. This rule describes the Department's responsibilities for processing permit applications and making permit decisions on those permit applications that do not require the preparation of an environmental impact statement.

11. ARM 17.8.762 Duration of Permit. An air quality permit shall be valid until revoked or modified, as provided in this subchapter, except that a permit issued prior to construction of a new or modified source may contain a condition providing that the permit will expire unless construction is commenced within the time specified in the permit, which in no event may be less than 1 year after the permit is issued.

12. ARM 17.8.763 Revocation of Permit. An air quality permit may be revoked upon written request of the permittee, or for violations of any requirement of the Clean Air Act of Montana, rules adopted under the Clean Air Act of Montana, the FCAA, rules adopted under the FCAA, or any applicable requirement contained in the Montana State Implementation Plan (SIP).

13. ARM 17.8.764 Administrative Amendment to Permit. An air quality permit may be amended for changes in any applicable rules and standards adopted by the Board of Environmental Review (Board) or changed conditions of operation at a source or stack that do not result in an increase of emissions as a result of those changed conditions. The owner or operator of a facility may not increase the facility's emissions beyond permit limits unless the increase meets the criteria in ARM 17.8.745 for a de minimis change not requiring a permit, or unless the owner or operator applies for and receives another permit in accordance with ARM 17.8.748, ARM 17.8.749, ARM 17.8.752, ARM 17.8.755, and ARM 17.8.756, and with all applicable requirements in ARM Title 17, Chapter 8, Subchapters 8, 9, and 10.

14. ARM 17.8.765 Transfer of Permit. This rule states that an air quality permit may be transferred from one person to another if written notice of intent to transfer, including the names of the transferor and the transferee, is sent to the Department.

15. ARM 17.8.770 Additional Requirements for Incinerators. This rule specifies the additional information that must be submitted to the Department for incineration facilities subject to 75-2-215, MCA.

G. ARM 17.8, Subchapter 8 – Prevention of Significant Deterioration of Air Quality, including, but not limited to:

1. ARM 17.8.801 Definitions. This rule is a list of applicable definitions used in this subchapter.

2. ARM 17.8.818 Review of Major Stationary Sources and Major Modifications--Source Applicability and Exemption. The requirements contained in ARM 17.8.819 through ARM 17.8.827 shall apply to any major stationary source and any major modification, with respect to each pollutant subject to regulation under the FCAA that it would emit, except as this chapter would otherwise allow.

   MRC's existing petroleum refinery in Great Falls is defined as a "major stationary source" because it is a listed source with the PTE more than 100 tons of several pollutants (PM, SO_2, NO_x, CO, and VOCs).

H. ARM 17.8, Subchapter 9 – Permit Requirements for Major Stationary Sources or Modifications Located within Nonattainment Areas, including, but not limited to:

1. ARM 17.8.904 When A Montana Air Quality Permit Required. This rule requires that major stationary sources or major modifications located within a nonattainment area must obtain a MAQP in accordance with the requirements of this subchapter, as well as the requirements of Subchapter 7.

I. ARM 17.8, Subchapter 12 – Operating Permit Program Applicability, including, but not limited to:

1. ARM 17.8.1201 Definitions. (23) Major Source under Section 7412 of the FCAA is defined as any stationary source having:

   a. PTE > 100 TPY of any pollutant;

b. PTE > 10 TPY of any one HAP, PTE > 25 TPY of a combination of all HAPs, or a lesser quantity as the Department may establish by rule; or

c. PTE > 70 TPYof particulate matter with an aerodynamic diameter less than 10 microns (PM_{10}) in a serious PM_{10} nonattainment area.

2. ARM 17.8.1204 Air Quality Operating Permit Program. (1) Title V of the FCAA Amendments of 1990 requires that all sources, as defined in ARM 17.8.1204(1), obtain a Title V Operating Permit. In reviewing and issuing MAQP #2161-25 for MRC, the following conclusions were made:

   a. The facility's PTE is greater than 100 TPY for several pollutants.

   b. The facility's PTE is greater than 10 TPY for any one HAP and greater than 25 TPY of all HAPs.

   c. This source is not located in a serious PM10 nonattainment area.

   d. This facility is subject to NSPS requirements (40 CFR 60, Subparts A, J, Dc, Kb, UU, GGG, and QQQ).

   e. This facility is subject to current NESHAP standards (40 CFR 63, Subparts A, R, CC, UUU, and EEEE).

   f. This source is not a Title IV affected source.

   g. This facility is not a solid waste combustion unit.

   h. This source is not an EPA designated Title V source.

   Based on these facts, the Department determined that MRC is a major source of emissions as defined under Title V. MRC's current Operating Permit, #OP2161-05, became final on March 29, 2011. The current permit action will also require a modification to MRC's Title V Operating Permit.

III. BACT Analysis

A BACT determination is required for each new or modified source. MRC shall install on the new or modified source the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized.

A BACT analysis was submitted by MRC in MAQP application #2161-25. The BACT analysis addresses some available methods of controlling PM, PM_{10}, $PM_{2.5}$, NOx CO, VOC emissions from the # 3 Boiler. It is important to note that the use of the term refinery fuel gas throughout the analysis would also include SWSOH. According to information provided by MRC and pursuant to EPA's applicability determination index (ADI) document control #9900013, the definition of fuel gas is any gas generated at the refinery, and gas that is combusted at the refinery. MRC estimated that the SWSOH gas going to the #3 Boiler would never exceed 10 %.

The Department reviewed the available control methods, as well as previous BACT determinations for similarly permitted sources. The following text provides a summary of the BACT analysis submitted by MRC and the Department's BACT determination(s) based on the information provided.

BACT Analysis for NO_X Emissions – #3 Boiler

As an introduction to the detailed discussion of NO_X control technologies, it is useful first to review the mechanisms by which NO_X is formed in the exhaust from a boiler. NO_X refers to the cumulative emissions of nitric oxide (NO), nitrogen dioxide (NO_2), and trace quantities of other species. NO_X emissions from combustion processes are typically more than 95 percent NO with the remainder being primarily NO_2. Once the flue gas leaves the stack, however, most of the NO is oxidized in the atmosphere to create NO_2 in a process that can take several hours to complete. The extent to which the NO is oxidized to NO_2 is a function of a number of meteorological variables, including ambient ozone levels.

The two primary mechanisms attributed to the formation of NO_X are: thermal NO_X and fuel NO_X. MRC proposes to use natural gas or refinery fuel gas as a fuel source and approximately up to 10 percent SWSOH. With these types of fuels, the fuel NO_X portion is usually relatively low. Thermal NO_X refers to the NO_X formed through high-temperature oxidation of the nitrogen found in the combustion air. The primary factors contributing to an increased thermal NO_X formation rate are the same factors contributing to complete combustion of fuel: combustion temperature, residence time, and mixing or turbulence. Regardless of the fuel being combusted, thermal NO_X generally becomes a significant factor at combustion temperatures of approximately 2,200 degrees Fahrenheit (ºF), with exponential increases in formation rate at higher temperatures. The maximum thermal NO_X production generally occurs at slightly lean fuel-to-air ratio due to the excess availability of oxygen for the reaction with nitrogen in the air and fuel.

Fuel NO_X refers to the NO_X formed by the conversion of fuel-bound nitrogen to NO_X during combustion. Fuel NO_X accounts for a major portion of the total NO_X emissions from the combustion of nitrogen containing fuels, such as coal and wood waste. A variety of factors, including the combustion temperature, fuel-air stoichiometric ratio, and fuel characteristics (moisture, volatile matter, and nitrogen) are believed to contribute to the fuel NO_X formation mechanism. Generally speaking, the fuel NO_X formation is minimal when combusting refinery fuel gas and/or pipeline quality natural gas.

The most prevalent combustion control techniques used to reduce NO_X emissions from gas-fired boilers are flue gas recirculation (FGR), and ultra low NO_X burners (ULNB). Post-combustion gas treatment techniques ultimately utilized for the reduction NO_X includes selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR). It is important to note that some of these control techniques can be used in combination with each other.

ULNB technology incorporates staged combustion that creates a fuel-rich primary combustion zone. The use of ULNB generally results in decreased fuel NO_X formation due to conditions in the primary combustion zone, and limited thermal NO_X formation results because of a lower flame temperature caused by the lower oxygen concentration. There are a few potential disadvantages to using ULNB technology in that facilities may see an increase in CO emissions and hydrocarbon emissions, and decreased boiler efficiency with increased fuel costs.

FGR is a flame quenching technique used to recirculate a portion of the flue gas that is recycled from the stack back to the burner. FGR reduces the peak flame temperature and the oxygen in the combustion zone through absorption of the combustion heat by a cooler flue gas. The amount of recirculated flue gas can be the biggest influence when operating these types of systems.

SCR is a post combustion technique whereby ammonia is injected into the flue gas upstream of the catalyst bed. NO_X and ammonia combine at the catalyst surface which forms an ammonium salt that later decomposes to produce elemental nitrogen and water. This technology works best for flue gas temperatures between 575 ºF – 750 ºF with optimum temperatures between 480 ºF to 800 ºF. There are many factors that could influence effectiveness of the technology including:

inlet NO_X concentrations, catalyst reactor design (e.g. catalyst reactivity, poisoning and catalyst failure). However, use of SCR can achieve 70-90% control for many industrial combustion sources.

SNCR involves the non-catalytic decomposition of NO_X in the flue gas to nitrogen and water using a reducing agent such as ammonia or urea. It is a similar reaction as the SCR however, the reaction take place at much higher temperatures (usually between 1,600°F and 1,800°F) because the catalyst does not drive the reaction. The efficiency declines quickly when operated outside the optimum temperature range and causes ammonia slip or excess NO_X emissions. Ammonia slip is emissions of unreacted ammonia that result from incomplete reaction of the NO_X with the reagent. According to EPA, the estimated control efficiency for SNCR alone would be 30%-50%. When used in conjunction with combustion controls (such as ULNB) then SNCR can achieve reductions of 65-75%.

Although all of these technologies would be considered technically feasible, with an exit gas temperature of approximately 300° F, the use of SNCR and SCR would require additional heating of the gas stream. The additional heating of the gas stream would result in additional energy consumption, additional cost and result in an increase in NO_X emissions (approximately 13 tpy for SNCR and 1.1 tpy for SCR). Currently, the boiler has an estimated PTE of approximately 5 tpy without control. Additionally, due to the low performance of SNCR relative to SCR, SNCR is not a common control option for boilers of this size. Therefore, because of the potential for increased air emissions, and the technical difficulties associated with this control technology, the Department determined that SNCR does not constitute BACT in this case.

Capital costs associated with SCR are usually significantly higher than most other control technologies and are generally more cost effective for larger industrial boilers. Additionally, the use of SCR technology has a potential for unreacted ammonia in the flue gas (ammonia slip) which results from incomplete reaction of the NO_X with the reagent. Ammonia slip could cause formation of ammonium sulfates and cause fouling of downstream equipment, and increased opacity or visibility of the exhaust plume. Like NSCR, SCR would require additional heating of the gas stream which would result in additional energy consumption, additional cost and could result in an increase in NO_X emissions (MRC calculated that additional 1.1 tpy of NO_X emissions would result by increasing the temperature of the flue gas to 600° F.). MRC determined that the increase in NO_X emissions would offset NO_X reductions thereby reducing SCR control efficiency from approximately 90% to 69 %. Other potential environmental impacts considered with the use of SCR would include reagent storage and the potential for accidental releases of ammonia in a populated area.

MRC provided an economic impact analysis to show that use of the SCR control technology would result in an estimated cost-effectiveness of $132,000 per ton of NO_X removed. Given the high cost, and those items listed above, the Department determined that SCR does not constitute BACT in this case.

ULNB with FGR has been considered a standard installation of a modern boiler package and when these techniques are applied together and they are capable of 60-90 percent reduction of NO_X. Because these controls are considered standard with most modern boiler packages, the cost of the equipment is included with the cost of the boiler. As such, no additional costs of NO_X removal were evaluated. This combination of controls was found to result in acceptable environmental and energy impacts. Therefore, the Department determined that the use of ULNB+FGR with a NO_X emissions limitation of 0.019 lb/MMBtu based on three-hour average constitutes BACT for the #3 Boiler. This is similar to other recently permitted facilities and is supported by an evaluation of permitting actions with similar properties as listed in EPA's RACT/BACT/LEAR Clearinghouse (RBLC).

BACT Analysis for VOC and CO Emissions – #3 Boiler

CO and VOC emissions are formed from incomplete organic fuel combustion. CO and VOCs are usually generated and controlled in the same manner. However, in this case the VOC emissions are estimated at 0.26 tpy and the Department determined that no control technology would be economically feasible at this level. However, many of the CO control technologies serve to reduce VOC emissions as well.

Ideally, complete combustion of the fuel, or oxidation results in conversion to water and carbon dioxide. When the organic compounds do not oxidize completely, the facility will have increased CO and VOC emissions. Improving combustion conditions in the boiler ultimately improves combustion in the burner and as a result, the exhaust stream could be completely oxidized when it leaves the boiler burner. Based on the options available, the following control alternatives were evaluated:

- Proper system design and operation (good combustion techniques);
- Thermal oxidation; and
- Catalytic oxidation.

Reduction of CO can be accomplished through proper system design and operation by ultimately controlling the combustion temperature, residence time, and available oxygen. It is critical to balance these because CO reduction techniques could result in NO_X emissions increase. Maximizing heating efficiency and minimizing fuel usage would result in less CO emissions.

Thermal oxidation is accomplished through supplementary combustion chambers that complete the conversion of CO to CO_2 and water by creating a high temperature environment with optimal oxygen concentration, mixing, and residence time. Thermal oxidizers used to control CO generally require operation at high temperatures of approximately 1600 ºF but result in control efficiencies of approximately 95-99%. The use of thermal oxidation not only requires high-temperature environment, but also requires supplemental fuel such as natural gas.

A regenerative thermal oxidizer (RTO), which is a commonly used design for thermal oxidation, is usually a bed of ceramic packing material used to capture heat from the incineration process and preheat the incoming exhaust gas. RTOs are more frequently used to reduce VOC emissions, and are not widely used to reduce CO emissions. Generally speaking, thermal incinerators have relatively high costs due to the required supplemental fuel costs. These types of devices are not conducive to sources with variable flows because this impact residence time and poor mixing which decreases complete combustion. As a result, the combustion chamber temperature falls decreasing the destruction efficiency. RTOs are capable of reducing CO emissions by 95 to 99 percent; however, increases in additional NO_X and CO emissions might be expected as a result of combustion of the additional natural gas to raise the exhaust temperature.

Catalytic oxidation is very similar to thermal oxidizers, but this process requires a catalyst bed generally located in the boiler exhaust to complete the conversion of CO to CO_2 and water. The most common design is a regenerative catalytic oxidizer (RCO). The optimum temperature for this type of control ranges from 600 ºF – 800 ºF. The downside of using a catalyst is that they are prone to plugging and catalyst poisoning. When particulate in the exhaust stream is a problem, then a particulate control device would also be required downstream. The #3 Boiler would combust clean fuels (such as RFG and natural gas) and particulate loading would not be a problem. Unlike RTOs which are not known to reduce levels of CO, the RCO that utilizes a metal based catalyst can destroy 98% of the CO in a VOC laden stream.

MRC design calculations estimate the boiler exhaust temperature to be approximately 300 ºF. Both of the control technologies evaluated would require auxiliary heating to increase the temperature of the exhaust in order to be feasible. The addition of fuel required to increase the temperature of the exhaust stream would result in an emissions increase (estimated at 2.9 tpy of NO_X and 1.8 tpy of CO). MRC provided a cost analysis based on general application of RCO (e.g. not design specific). Given the minimal amount of emissions that would result from this project and the economic cost impact of $63,006 per ton of CO removed; the Department determined that neither RTO or RCO would constitute BACT for the removal of CO or VOCs.

Proper operation, design and good combustion techniques are often chosen as CO control for boilers. For this application, proper system design and operation has been demonstrated to have acceptable environmental, energy, and economic impacts. Based on this information, MRC proposed and the Department concurs that proper system design and operation and a CO emissions limitation of 0.034 lb/MMBtu based on a 3-hour average constitutes CO BACT for the #3 Boiler.

Additionally, because CO and VOC are generated and controlled by the same mechanisms and because VOC emissions closely mimic CO emissions, the Department determined that proper operation and design would constitute BACT for VOCs also.

BACT Analysis for SO_2 Emissions – #3 Boiler

Inherently, natural gas has negligible sulfur content and based on information provided in the application, MRC's refinery fuel gas also has low sulfur content. Both fuels result in low annual SO_2 emissions. In reviewing RBLC and past BACT determinations for similar emitting units, the Department determined that the use of additional controls for SO_2 emissions is cost-prohibitive. Currently, any fuel burned in the #1 and #2 Boilers must meet the applicable limitations in 40 CFR 60, Subpart J, and MRC proposed that the #3 Boiler also meet this requirement. Therefore, the use of pipeline quality natural gas and/or refinery fuel gas with SO_2 emissions not to exceed 20 ppmvd at 0% oxygen (equivalent to based on a 3-hour average constitutes BACT for SO_2.

BACT Analysis for $PM/PM_{10}/PM_{2.5}$ Emissions – #3 Boiler

Because of the relatively small amount of PM emissions produced by the #3 Boiler and the fact that particulate controls are rarely applied to this type of boiler, the Department determined that add-on control would be cost prohibitive. Additionally, natural gas and RFG have negligible ash content and the annual $PM/PM_{10}/PM_{2.5}$ emissions are low (less than 3 tpy). Therefore, the Department determined that the use of pipeline quality natural gas or refinery fuel (including SWSOH) gas as fuel for the boilers in addition to proper design and good combustion techniques constitute BACT for $PM/PM_{10}/PM_{2.5}$. This is consistent with other recently permitted sources.

IV. Emission Inventory

Emission Source	Emissions (TPY)							
	PM	PM_{10}	$PM_{2.5}$	NO_x	VOC	CO	SO_x	HAPs
#3 Boiler	2.65	2.65	1.98	5.03	1.43	9.01	7.66	0.565

Boiler Heating value:	60.5	MMBtu/hr		
Operating hours:	8760	hrs/year		
Stack Height	165	feet		
Exit Gas Temp	281	Fahrenheit		
Exit Gas flowrate (ACFM)		20600	ACFM	(per application)
Exit Gas velocity (fps)	160	fps		

PM Emissions					
Emission Factor:	0.01	lb/MMBtu	(manufacturer information)		
Calculations:	0.01 lb/MMBtu * 60.5 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =			2.65	tons/yr
PM10 Emissions					
Emission Factor:	0.01	lb/MMBtu	(manufacturer information)		
Calculations:	0.01 lb/MMBtu * 60.5 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =			2.65	tons/yr
PM2.5 Emissions					
Emission Factor:	0.00745	lb/MMBtu	(Filt + Cond, AP-42, Table 1.4-2, 7/98)		
Calculations:	0.00745 lb/MMBtu * 60.5 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =			1.97	tons/yr
CO Emissions					
Emission Factor:	0.034	lb/MMBtu	(BACT Determination)		
Calculations:	0.034 lb/MMBtu * 60.5 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =			9.01	tons/yr
NOx Emissions					
Emission Factor:	0.019	lb/MMBtu	(BACT determination)		
Calculations:	0.019 lb/MMBtu * 60.5 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =			5.03	tons/yr
SOx Emissions					
Emission Factor:	0.0289	lb/MMBtu	(BACT, 20 ppmv at 0% O2)		
Calculations:	0.0289 lb/MMBtu * 60.5 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =			7.66	tons/yr
VOC Emissions					
Emission Factor:	0.0054	lb/MMBtu	(natural gas, AP-42, Table 1.4-2, 7/98)		
Calculations:	0.0054 lb/MMBtu * 60.5 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =			1.43	tons/yr
HAP Emissions	*See HAP worksheet (on file with Department)*			0.565	tons/yr

V. Existing Air Quality

As of July 8, 2002, Cascade County is designated as an Unclassifiable/Attainment area for NAAQS for all criteria pollutants. Previous to that date, MRC was located outside, but adjacent to, a CO nonattainment area in downtown Great Falls. On December 2, 1985, the Montana Department of Health and Environmental Sciences and MRC signed a stipulation requiring MRC to obtain an air quality permit and stipulating a permit emission limitation of 4,700 TPY CO, when considered in conjunction with control measures on other sources such as automobiles, would achieve compliance with ambient CO standards. This permit limits plant-wide CO emissions to 4,700 TPY.

In 1993, the Department conducted preliminary ambient air quality modeling for SO_2 using the COMPLEX1 and ISC2 models and meteorological data collected from the Great Falls Airport assuming 7 tons per day of SO_2 emissions. The results of the model previously demonstrated that at 7 tons per day of emissions, this facility causes a violation of the state and federal SO_2 ambient standards. As a result, MRC was limited to 5.25 tons per day of plant-wide refinery SO_2 emissions (MAQP #2161-06) in the first step of a plan to achieve attainment. In April 1998, MRC submitted additional modeling to demonstrate compliance with the NAAQS for SO_2. In June 1999, this modeling, and the permit application were determined to be complete. The permitting action established limitations that demonstrate compliance with the NAAQS and MAAQS for SO_2. The facility is now limited to 4.15 tons per rolling 24-hours of plant-wide refinery SO_2 emissions (or 1515 TPY). An ambient air-monitoring plan will continue to be used to monitor SO_2 emissions.

VI. Ambient Air Impact Analysis

The Department determined that based on the relatively minor amount of emissions resulting from this permit action, in addition to the limits and conditions included in MAQP #2161-25, the impacts from this permitting action will be minor. The Department believes the current permit action will not cause or contribute to a violation of any ambient air quality standard.

For the current permit action, MRC conducted significant impact level (SIL) analyses for the following pollutants: CO, particulate matter (PM), NO_X, and SO_2. All of the #3 Boiler emissions were below the MDEQ modeling thresholds so modeling was not required. However, given the fact that the area has historically been concerned with SO_2, the Department required MRC to perform a SIL analysis. The SIL analysis serves as a screening tool to identify the impacts from the proposed source emissions only. If the impact from a project emissions is less than a SIL, the impacts can be considered de minimums or trivial. If the SIL is exceeded, all nearby industrial emission sources need to be included within the radius of impact (ROI) plus 50 km for further modeling.

The results of the SIL modeling are presented in the table below. The highest modeled concentrations were listed in this table unless noted otherwise. The Great Falls International Airport (GF) meteorological year that produced these results is also noted in parentheses, if applicable.

MRC - Class II, Significant Impact Level AERMOD Modeling.

Pollutant	Averaging Period	Modeled Concentration ($\mu g/m^3$)[1, 2]	Class II SIL ($\mu g/m^3$)	Percent of SIL (%)	Significant? (Y/N)
CO	1-Hour	5.26 (GF 2001)	2,000	0.3	N
	8-Hour	1.74 (GF 2001)	500	0.4	N
PM_{10}	24-Hour	0.27 (GF 2000)	5	5.4	N
	Annual	0.04 (GF 2002)	1	4.0	N
$PM_{2.5}$	24-Hour	0.07 (GF 2000)	1.2	5.8	N
	Annual	0.01 (GF 2002)	0.3	3.3	N
NO_x	1-Hour	2.68[3]	7.5[4]	35.7	N
	Annual	0.07 (GF 2002)	1	7.0	N
SO_2	1-Hour	4.28[5]	7.86[6]	54.5	N
	3-Hour	3.05 (GF 2001)	25	12.2	N
	24-Hour	0.78 (GF 2000)	5	15.6	N
	Annual	0.11 (GF 2002)	1	11.0	N

1. $\mu g/m^3$ = micrograms per cubic meter.
2. All selected concentrations were high-first-high (H1H), unless otherwise noted.
3. Oris NO2Post AERMOD post-processor was used to calculate the highest 1-hour NO_2 concentration at a receptor over the 5 years of met data.
4. USEPA interim SIL, based on 4% of the 1-hour NO_2 NAAQS.
5. Oris SO2Post AERMOD post-processor was used to calculate the highest 1-hour SO_2 concentration at a receptor over the 5 years of met data.
6. USEPA interim SIL, based on 4% of the 1-hour SO_2 NAAQS.

As a result of this analysis, the Department determined the #3 Boiler will not cause or contribute to a violation of a NAAQS.

VII. Taking or Damaging Implication Analysis

As required by 2-10-105, MCA, the Department conducted the following private property taking and damaging assessment.

YES	NO	
X		1. Does the action pertain to land or water management or environmental regulation affecting private real property or water rights?
	X	2. Does the action result in either a permanent or indefinite physical occupation of private property?
	X	3. Does the action deny a fundamental attribute of ownership? (ex.: right to exclude others, disposal of property)
	X	4. Does the action deprive the owner of all economically viable uses of the property?
	X	5. Does the action require a property owner to dedicate a portion of property or to grant an easement? [If no, go to (6)].
		5a. Is there a reasonable, specific connection between the government requirement and legitimate state interests?
		5b. Is the government requirement roughly proportional to the impact of the proposed use of the property?
	X	6. Does the action have a severe impact on the value of the property? (consider economic impact, investment-backed expectations, character of government action)
	X	7. Does the action damage the property by causing some physical disturbance with respect to the property in excess of that sustained by the public generally?
	X	7a. Is the impact of government action direct, peculiar, and significant?
	X	7b. Has government action resulted in the property becoming practically inaccessible, waterlogged or flooded?
	X	7c. Has government action lowered property values by more than 30% and necessitated the physical taking of adjacent property or property across a public way from the property in question?
	X	Takings or damaging implications? (Taking or damaging implications exist if YES is checked in response to question 1 and also to any one or more of the following questions: 2, 3, 4, 6, 7a, 7b, 7c; or if NO is checked in response to questions 5a or 5b; the shaded areas)

Based on this analysis, the Department determined there are no taking or damaging implications associated with this permit action.

VIII. Environmental Assessment

An environmental assessment, required by the Montana Environmental Policy Act, was completed for this project. A copy is attached.

DEPARTMENT OF ENVIRONMENTAL QUALITY
Permitting and Compliance Division
Air Resources Management Bureau
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FINAL ENVIRONMENTAL ASSESSMENT (EA)

Issued For: Montana Refining Company (MRC)
1900 10th Street North East
Great Falls, MT 59404

Montana Air Quality Permit Number (MAQP): #2161-25

Preliminary Determination Issued: 12/21/2011
Department Decision Issued: 01/24/2012
Permit Final: 02/09/2012

1. *Legal Description of Site*: MRC is located at 1900 10th Street N.E. in Great Falls, Montana. The legal description of the site is the NE¼ of Section 1, Township 20 North, Range 3 East, Cascade County, Montana.

2. *Description of Project*: On July 6, 2011, MRC submitted a permit application and subsequent modeling demonstration to add a boiler (#3 Boiler) capable of firing refinery fuel gas or natural gas to the petroleum refinery. The Department deemed the application incomplete on August 4, 2011 and MRC provided additional information in response to the Department's letter on September 26, 2011. The primary purpose of the #3 Boiler is to supplement the two existing boilers #1 and #2 that provide process steam to the refinery. The design burner heat input capacity for Boiler #3 varies depending upon fuel characteristics from 59.7 to 60.5 million british thermal units per hour (MMBtu/hr).

3. *Objectives of Project*: To install and construct a new boiler (#3 Boiler) that will provide steam to the existing refinery and supplement the #1 and #2 Boilers.

4. *Additional Project Site Information*: This refinery has operated at this site since the 1920's. The refinery currently employs 90 people, and is located along the Missouri River in Great Falls, Montana.

5. *Alternatives Considered*: In addition to the proposed action, the Department considered the "no-action" alternative. The "no-action" alternative would deny issuance of the air quality preconstruction permit to the proposed facility. However, the Department does not consider the "no-action" alternative to be appropriate because MRC demonstrated compliance with all applicable rules and regulations as required for permit issuance. Therefore, the "no-action" alternative was eliminated from further consideration.

6. *A Listing of Mitigation, Stipulations, and Other Controls*: A listing of the enforceable permit conditions and a permit analysis would be contained in MAQP #2161-25.

7. *Regulatory Effects on Private Property Rights*: The Department considered alternatives to the conditions imposed in this permit as part of the permit development. The Department determined the permit conditions would be reasonably necessary to ensure compliance with applicable requirements and to demonstrate compliance with those requirements and would not unduly restrict private property rights.

8. *The following table summarizes the potential physical and biological effects of the proposed project on the human environment. The "no action alternative" was discussed previously.*

		Major	Moderate	Minor	None	Unknown	Comments Included
A.	Terrestrial and Aquatic Life and Habitats			X			yes
B.	Water Quality, Quantity, and Distribution			X			yes
C.	Geology and Soil Quality, Stability, and Moisture			X			yes
D.	Vegetation Cover, Quantity, and Quality			X			yes
E.	Aesthetics			X			yes
F.	Air Quality			X			yes
G.	Unique Endangered, Fragile, or Limited Environmental Resource				X		yes
H.	Demands on Environmental Resource of Water, Air, and Energy			X			yes
I	Historical and Archaeological Sites				X		yes
J.	Cumulative and Secondary Impacts			X			yes

SUMMARY OF COMMENTS ON POTENTIAL PHYSICAL AND BIOLOGICAL EFFECTS: The following comments have been prepared by the Department.

A. Terrestrial and Aquatic Life and Habitats

Impacts on terrestrial and aquatic life would be minimal. MRC is an existing facility that is currently permitted to use two boilers (#1 and #2). MRC requested to add a third boiler to supplement the existing boiler system and to possibly replace the old boilers in the future. Because the plant is an existing facility, a slight increase in emissions would cause little additional impacts to terrestrial or aquatic life and habitats. During construction, the area would change slightly but overall there would be minor changes. Therefore, any associated impacts would be minor.

B. Water Quality, Quantity, and Distribution

Any impacts on water quality, quantity or distribution, if any, would be minor because this permit modification would not require additional water. There is the potential for impacts to groundwater or stormwater due to spills and leaks, but these risks should be addressed in the facility's SPCC plan. Therefore, the overall characteristics of the area would not change as a result of the proposed project and any associated impacts would be minor.

C. Geology and Soil Quality, Stability, and Moisture

The proposed permit modification would have minor impacts on geology and soil quality, stability and moisture because deposition of air pollutants on soils would be minor (see Section 8.F of this EA). Only minor amounts of additional pollution would be generated. Pollutants would be widely dispersed before settling upon vegetation and surrounding soils (see Section 8.D of this EA). The permit modification would not result in minor disturbance of soils during construction because the area has been previously disturbed and currently occupied by the petroleum refinery. Therefore, any additional effects upon geology and soil quality, stability, and moisture at this site would be minor and short-term.

D. Vegetation Cover, Quantity, and Quality

Minor or no impacts would occur on vegetative cover, quality, and quantity because operation of the #3 Boiler would be used to supplement steam supply (from the #1 and #2 Boiler). The boiler would be located in an industrial area within an existing refinery. Boiler emissions would contribute minor additional pollutants but the pollutants would be greatly dispersed. Any corresponding deposition on vegetation from the proposed project would be minor (see Section 8.F of this EA). Therefore, the Department determined that any associated impacts upon vegetation would be minimal.

E. Aesthetics

The existing operation would be visible and could create additional noise while operating; however, impacts to aesthetics associated with adding a new boiler would result in minor changes to aesthetics. MAQP #2161-25 would include conditions to control emissions, including visible emissions, from the plant. Therefore, impacts to area aesthetics as a result of the proposed permit modification would be minor.

F. Air Quality

Air quality impacts from the proposed project would be minor. MAQP #2161-25 includes emission limits for the #3 Boiler and additional pollutant deposition from the proposed project would be minimal. The pollutants emitted are mainly gaseous, and would be widely dispersed (from factors such as wind speed and wind direction) and would have minimal deposition on the surrounding area (due to site topography of the area and minimal vegetative cover in the area). Additionally, MRC submitted a modeling demonstration to show that the new boiler would not cause or contribute to a violation of the NAAQS. Therefore, air quality impacts in this area as a result of this permit action would be minor.

G. Unique Endangered, Fragile, or Limited Environmental Resources

Since a refinery has operated at this site since the 1920's and the area is fenced, the permit modification would not result in any disturbance to unique endangered, fragile, or limited environmental resources. The Department determined that the proposed project would not impact any species of concern.

H. Demands on Environmental Resources of Water, Air, and Energy

There will be no additional demands on water resources due to this permit modification. There will be minimal impacts to air resources because the source is located at an existing industrial source of emissions. Air pollutants generated due to this modification would be limited and widely dispersed (see Section 8.F of this EA). There would be a negligible change in energy requirements because this boiler consumes a minimal amount of energy when compared to the rest of the existing facility. Overall, any impacts of the proposed project to water, air, and energy resources would be minor.

I. Historical and Archaeological Sites

The proposed project would occur within the boundaries of the MRC facility, a previously disturbed industrial site. The Montana State Historic Preservation Office previously informed the Department that there is low likelihood of adverse disturbance to any known archaeological or historic site, given previous industrial disturbance within a given area. Because there would be no additional ground disturbance, there would be no known effect on any historic or archaeological site.

J. Cumulative and Secondary Impacts

Additional emissions generated from the proposed project would, at most, result in only minor impacts to the area of operations because the proposed equipment is located within the existing refinery facility, which has other sources of emissions that are much larger. This modification would be minor in comparison and the overall, cumulative and secondary impacts to the physical and biological aspects of the human environment would be minor.

9. *The following table summarizes the potential economic and social effects of the proposed project on the human environment. The "no action alternative" was discussed previously.*

		Major	Moderate	Minor	None	Unknow n	Comments Included
A.	Social Structures and Mores				X		yes
B.	Cultural Uniqueness and Diversity				X		yes
C.	Local and State Tax Base and Tax Revenue			X			yes
D	Agricultural or Industrial Production				X		yes
E.	Human Health			X			yes
F.	Access to and Quality of Recreational and Wilderness Activities				X		yes
G	Quantity and Distribution of Employment				X		yes
H.	Distribution of Population				X		yes
I.	Demands for Government Services			X			yes
J.	Industrial and Commercial Activity				X		yes
K.	Locally Adopted Environmental Plans and Goals			X			yes
L.	Cumulative and Secondary Impacts			X			yes

SUMMARY OF COMMENTS ON POTENTIAL ECONOMIC AND SOCIAL EFFECTS: *The following comments have been prepared by the Department.*

A. Social Structures and Mores

The proposed project would cause no disruption to the social structures and mores in the area because the modification would occur within an existing industrial source. Further, the facility would be required to operate according to the conditions that would be placed in MAQP #2161-25. No native or traditional communities would be affected by the proposed project operations and no impacts upon social structures or mores would result.

B. Cultural Uniqueness and Diversity

The predominant use of the area is an existing refinery. Because the predominant use of this area has historically been refinery operations, and the fact that the refinery's operation would result in minor changes and limited emissions, there would be minor impacts resulting from this permit modification. Therefore, the cultural uniqueness and diversity of the area would not be impacted by this permit action.

C. Local and State Tax Base and Tax Revenue

The proposed project would have little, if any, impact on the local and state tax base and tax revenue because the proposed project would be at an existing industrial source. The proposed project would not require any additional employees. Thus, only minor impacts to the local and state tax base and revenue would be expected.

D. Agricultural or Industrial Production

The permit modification would occur within an existing refinery that is located in an industrial/commercial area. The project would not result in temporary ground disturbance. There would be no impact to existing agricultural land as the new boiler would be located within the already established industrial area. There are no expected effects on agricultural production, and minor effects on industrial production.

E. Human Health

MAQP #2161-25 would incorporate conditions to ensure that the proposed permit modification would be operated in compliance with all applicable air quality rules and standards. These rules and standards are designed to be protective of human health. The additional emissions from this permit modification would be minimal. As described in Section 8.F of this EA, any additional emissions that would result would be minimized by conditions in MAQP #2161-25. Therefore, only minor impacts would be expected on human health from the proposed project.

F. Access to and Quality of Recreational and Wilderness Activities

This project would not have an impact on recreational or wilderness activities because the new boiler would be constructed within an existing operation. The project would not result in any changes in access to and quality of recreational and wilderness activities.

G. Quantity and Distribution of Employment

There may be a few temporary employment opportunities during construction of the boiler. However, MRC does not anticipate any new employees as a result of this project. No individuals would be expected to permanently relocate to this area of operation as a result of the proposed project. Therefore, no effects upon the quantity and distribution of employment in this area would be expected.

H. Distribution of Population

No individuals would be expected to permanently relocate to this area of operation as a result of the proposed project. Therefore, the proposed project would not impact the normal population distribution in the area of operation.

I. Demands of Government Services

Minor government services would be required for acquiring the appropriate permits for the proposed project and verifying compliance with the permits that would be issued. Therefore, the Department believes that the demands for government services would be minor.

J. Industrial and Commercial Activity

MRC's proposed new boiler would locate at the existing refinery. The boiler would be used to supplement the existing boilers (#1 and #2). Overall, the refinery's production would remain the same. Therefore, the Department believes there would be minor changes to industrial and/or commercial activity.

K. Locally Adopted Environmental Plans and Goals

MAQP #2161-25 would contain limits for protecting air quality and to keep facility emissions in compliance with any applicable ambient air quality standards, which should be consistent with any locally adopted environmental plan or goal for operating at this proposed site.

L. Cumulative and Secondary Impacts

The proposed project would cause minor cumulative and secondary impacts to the social and economic aspects of the human environment in the immediate area of operation because the source is an existing operation. Further, no other industrial operations are expected to result from the permitting of this facility. The permit modification would not result in any permanent increases in traffic in the immediate area. Very little, if any increases in economic impacts to the local economy would be expected due to this permit modification. Thus, only minor and temporary cumulative and secondary effects would result.

Recommendation: An Environmental Impact Statement (EIS) is not required.

If an EIS is not required, explain why the EA is an appropriate level of analysis: All potential effects resulting from construction and operation of the proposed facility are negligible or minor; therefore, an EIS is not required.

Other groups or agencies contacted or which may have overlapping jurisdiction: Montana Department of Environmental Quality - Permitting and Compliance Division (Industrial and Energy Minerals Bureau); Montana Natural Heritage Program; and the State Historic Preservation Office (Montana Historical Society).

Individuals or groups contributing to this EA: Montana Department of Environmental Quality (Air Resources Management Bureau), Montana State Historic Preservation Office (Montana Historical Society).

EA prepared by: Jenny O'Mara
Date: December 7, 2011